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Sulfur Oxides Emissions from Fluid Catalytic Cracking Unit Regenerators: Background Information for Promulgated Standards

(U.S.) Environmental Protection Agency, Research Triangle Park, NC

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Background Information for Promulgated Standards

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Standards of performance to control emissions of sulfur oxides (SO_x) from new, modified, and reconstructed fluid catalytic cracking unit regenerators are being promulgated under Section 111 of the Clean Air Act. This document contains a summary of public comments, EPA responses, and a discussion of differences between the proposed and promulgated standard.

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Emissions Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
April 1989

1-A

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ENVIRONMENTAL PROTECTION AGENCY

Background Information and Final Environmental Impact Statement for Sulfur Oxides Emissions From Fluid Catalytic Cracking Unit Regenerators

Prepared by:

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Research Triangle Park, NC 27711

1. The emission standards will limit emissions of sulfur oxides from new, modified, and reconstructed fluid catalytic cracking unit regenerators at petroleum refineries. The standards implement Section 111 of the Clean Air Act and are based on the Administrator's determination of June 11, 1973 (38 FR 15380) that petroleum refineries contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

2. Copies of this document have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; the Council on Environmental Quality; members of the State and Territorial Air Pollution Program Administrators; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; and other interested parties.

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TABLE OF CONTENTS

Section Page

1.0 SUMMARY 1-1
  1.1 Summary of Changes Since Proposal 1-1
    1.1.1 Definition of Affected Facility 1-1
    1.1.2 Definition of Fresh Feed 1-2
    1.1.3 Methods for Compliance Determinations. . . . 1-2
    1.1.4 Definition of Regulated Pollutant 1-3
    1.1.5 Averaging Times for Compliance 1-4
    1.1.6 Clarification of Test Method Calculation Procedures and Sampling Locations 1-4
    1.1.7 Reduction in Reporting Requirements. 1-5
    1.1.8 Minor Changes 1-6
  1.2 Summary of Impacts of Promulgated Action 1-6
    1.2.1 Environmental Impacts of Promulgated Action 1-6
    1.2.2 Energy and Economic Impacts of Promulgated Action 1-6
    1.2.3 Other Considerations 1-6
      1.2.3.1 Irreversible and Irretrievable Commitment of Resources 1-6
      1.2.3.2 Environmental and Energy Impacts of Delayed Standards 1-7
  1.3 Summary of Public Comments 1-7

2.0 GENERAL COMMENTS 2-1
  2.1 Need for the Standards 2-1
  2.2 Regulated Pollutant 2-5
  2.3 Designation of Affected Facility 2-8
  2.4 Format of the Standards 2-11
  2.5 Level of Standards 2-16
    2.5.1 Level for Add-on Control Standard 2-16
    2.5.2 Level of Standard for FCCU's without Add-on Controls 2-17

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TABLE OF CONTENTS (Continued)

Section — Page

2.5.3 Feed Sulfur Cutoff 2-19
2.6 Averaging Times 2-19

3.0 CONTROL TECHNOLOGY COMMENTS 3-1
3.1 SO_x Scrubbers 3-1
3.2 SO_x Reduction Catalysts 3-6
3.3 Low-Sulfur Feedstocks 3-7

4.0 ENVIRONMENTAL AND ENERGY IMPACTS COMMENTS 4-1
4.1 Model Plants Used for Impact Analyses 4-1
4.2 Water Impacts 4-2
4.3 Solid Waste Impacts 4-7
4.4 Energy Impacts 4-10
4.5 Air Impacts 4-11

5.0 COSTS AND ECONOMIC IMPACTS COMMENTS 5-1
5.1 Scrubber Costs 5-1
5.2 SO_x Reduction Catalysts Costs 5-10
5.3 Economic Impact Analysis 5-11

6.0 COMPLIANCE TESTING AND MONITORING COMMENTS 6-1
6.1 General 6-1
6.2 With Add-On Control Devices 6-2
6.3 Without Add-On Control Devices 6-15
6.4 Feed Sulfur Cutoff 6-29

7.0 COMPLIANCE COMMENTS 7-1
7.1 Source Operation During Malfunctions 7-1
7.2 Compliance Using Partial Scrubbing 7-2
7.3 Changing Compliance Method 7-2

TABLE OF CONTENTS (Concluded)

Section Page

8.0 MODIFICATION/RECONSTRUCTION COMMENTS 8-1

9.0 RECORDKEEPING AND REPORTING COMMENTS 9-1

10.0 MISCELLANEOUS COMMENTS 10-1

APPENDIX A - Control Equipment Costs and Fifth Year Impacts

LIST OF TABLES

Table Page

1-1 LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR SULFUR OXIDES EMISSIONS FROM FCCU REGENERATORS 1-8

A-1 BASIS FOR DETERMINING SCRUBBER ANNUAL COSTS A-1

A-2 CAPITAL COST FOR SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING SYSTEM AND PURGE TREATMENT FOR MODEL UNITS A-2

A-3 ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR 2,500 m^3/sd MODEL UNITS . . . A-3

A-4 ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR 8,000 m^3/sd MODEL UNITS . . . A-4

A-5 ANNUAL COST OF SODIUM-BASED JET EJECTOR VENTURI SCRUBBING SYSTEM AND PURGE TREATMENT FOR MODEL UNITS A-5

A-6 ANNUAL COST OF SODIUM-BASED JET EJECTOR VENTURI SCRUBBING FOR 2,500 m^3/sd MODEL UNITS A-6

A-7 ANNUAL COST OF SODIUM-BASED JET EJECTOR VENTURI SCRUBBING FOR 8,000 m^3/sd MODEL UNITS A-7

A-8 DUAL ALKALI SCRUBBING SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED A-8

A-9 ELECTROSTATIC PRECIPITATOR COSTS A-9

A-10 FIFTH YEAR CAPITAL COST IMPACTS A-11

A-11 FIFTH YEAR ANNUAL COST IMPACTS A-12

1.0 SUMMARY

On January 17, 1984, the U.S. Environmental Protection Agency (EPA) proposed standards of performance for sulfur oxides (SO_x) emissions from fluid catalytic cracking unit (FCCU) regenerators at petroleum refineries (49 FR 2058) under the authority of Section 111 of the Clean Air Act. Public comments were requested on the proposed standards in the Federal Register and 18 commenters responded. On November 8, 1985, revisions to the proposed rule were proposed (50 FR 46464). The revisions included a change in the regulated pollutant for the standard for FCCU's with add-on controls, the determination of compliance on a daily basis, the methods for making the daily compliance determinations, and the averaging times over which the daily compliance determinations would be made. Public comments were requested on the proposed revisions and 12 commenters responded. Most of the commenters represented refining companies. Other commenters included two State air pollution control agencies, an industry trade association, an engineering company, and a private individual. This summary of comments and EPA's responses to these comments serve as the basis for the revisions made to the standards between proposal and promulgation.

1.1 SUMMARY OF CHANGES SINCE PROPOSAL

The proposed standards were revised as a result of reviewing public comments. The primary changes were made in the following areas:

- Definition of Affected Facility
- Definition of Fresh Feed
- Methods for Compliance Determinations
- Definition of Regulated Pollutant
- Averaging Times for Compliance
- Clarification of Test Method Calculation Procedures and Sampling Locations
- Reductions in Reporting and Compliance Testing Requirements

1.1.1 Definition of Affected Facility

The proposed standards identified each regenerator as the affected facility. This was done because SO_x are generated in and emitted from the FCCU regenerator. Some new FCCU's are designed to incorporate more than one regenerator. The EPA believes that identifying each FCCU regenerator as the affected facility for multiple regenerator configurations is unreasonable. If only one regenerator in a multiple regenerator configuration were to become subject to the standards, it would be impossible in some multiple regenerator ducting arrangements to isolate and measure the SO_x content of the exhaust gases from the affected regenerator. Furthermore, because the refiner would want to minimize the cost and downtime for revamping work on the unit, it is unlikely that only one regenerator in a multiple regenerator configuration would be modified or reconstructed without the others. Therefore, the affected facility is now defined to include all regenerators serving an FCCU reactor.

1.1.2 Definition of Fresh Feed

The standards include a feed sulfur cutoff, which limits the amount of sulfur that is allowed in the fresh feed to an FCCU. The possibility exists that a refiner could circumvent the feed sulfur cutoff by identifying as "fresh feed" hydrocarbon streams recycled from the fractionator or gas recovery unit because these units are not a part of the affected facility. Therefore, the definition of fresh feed was revised to ensure that a refiner would not circumvent the feed sulfur cutoff by including as "fresh feed" low sulfur-containing recycle from the fractionator and gas recovery units. The revised definition specifically identifies petroleum derivatives from the FCCU, the fractionator, and the gas recovery unit as "recycle", thus excluding them from the "fresh feed."

1.1.3 Methods for Compliance Determinations

At proposal, a continuous emission monitoring system (CEMS) was required to identify excess emissions, which were defined, for the standard for FCCU's with add-on controls, as sulfur dioxide (SO_2) in excess of the control device outlet concentration measured during the most recent performance test. The proposed standard specified the use of a continuous SO_2 emission monitoring system only at the control device outlet. (The standard for FCCU's without add-on controls also identified excess emissions, which were defined as SO_2 in excess of 300 vppm at 0 percent oxygen on a dry basis.) The EPA received comments that this approach would result in an unreasonable excess emissions limit when control device inlet concentrations changed from the level measured during the performance test. These comments, in part, led EPA to revise this approach to eliminate the dependence of the excess emission definition on the performance test.

Both the standards for FCCU's with add-on controls and for FCCU's without add-on controls now require determination of compliance on a daily basis, rather than using excess emissions to identify the need for a compliance test. The standard for FCCU's with add-on controls (90 percent reduction or 50 vppm, whichever is less stringent) now identifies SO_2 as the controlled pollutant and requires the use of continuous SO_2 monitors located at the control device inlet and outlet to determine the compliance status of the facility on a continual (i.e., daily) basis. Only an outlet continuous SO_2 monitor is required if the owner or operator seeks to comply specifically with only the 50 vppm emission limit. Because SO_2 monitors are now used for compliance determinations, they are subject to 40 CFR Part 60 Appendix F, "Quality Assurance Procedures, Procedure 1 - Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determination." The standard for FCCU's without add-on controls now requires daily Method 8 testing to demonstrate compliance with the 9.8 kg SO_x/1,000 kg coke burn-off standard.

For the standards for FCCU's with add-on control devices, minimum data requirements have been incorporated. They require 22 valid days of data out of every 30 successive, rolling calendar days. A valid day of data consists of at least 18 valid hours of data, where a valid hour of data consists of at least 2 valid data points.

1.1.4 Definition of Regulated Pollutant

As proposed on January 17, 1984, SO_x was the regulated pollutant for all the standards for FCCU's. After further consideration, the EPA concluded that the regulated pollutant for the standard for FCCU's with add-on control devices should be SO_2. The reasons for this change were: (1) as described above, the change to daily compliance determinations resulted in requiring both inlet and outlet monitors; (2) CEMS are not available for SO_x, but are available for SO_2; (3)

sulfur trioxide (SO_3) constitutes a small portion of total SO_x emissions; and (4) best demonstrated technology (i.e., scrubbers) would be essentially the same for SO_2 and SO_x.

For the standard for FCCU's without add-on control devices, the Agency concluded that the regulated pollutant should remain SO_x, because SO_3 could constitute a significant portion of the total SO_x emissions from FCCU's using SO_x reduction catalysts. These conclusions were included in the revisions proposed on November 8, 1985. No comments were received on using SO_2 as the regulated pollutant for FCCU's with add-on controls, but comments were received regarding SO_x as the regulated pollutant for FCCU's without add-on controls. No additional data or information was obtained that was sufficient for the Agency to conclude that SO_2 should be the regulated pollutant for FCCU's without add-on controls. Thus, the regulated pollutant for FCCU's with add-on control devices is SO_2 and for FCCU's without add-on control devices the regulated pollutant is SO_x.

1.1.5 Averaging Times for Compliance

The averaging times for compliance has changed since proposal from 3 hours to 7 days. The EPA analyzed source test results for scrubbers to determine the long term variability in scrubber performance and considered the effect of process variability on SO_x reduction catalyst performance. The analysis indicated that selection of a 7-day rolling average period for both the standards for FCCU's with add-on controls and for FCCU's without add-on controls would better take into consideration the normal variability. The proposed 7-day calendar averaging time for the feed sulfur cutoff was changed to a rolling 7-day average to be consistent with the averaging times for the other two standards, and so we would have daily compliance determinations.

1.1.6 Clarification of Test Method Calculation Procedures and Sampling Locations

The standard for FCCU's without add-on controls requires the use of Method 8 to determine the total SO_x emissions from affected facilities. The proposed standards did not provide sufficient information regarding calculation procedures for determining total SO_x emissions. The standards were revised to include modifications to the calculation procedures specified in Method 8 to allow calculation of total SO_x emissions as SO_2.

The proposed standards required that sampling to be conducted upstream of the carbon monoxide (CO) boiler. One commenter stated that it is unsafe to require personnel to conduct manual sampling due to the high flue gas temperatures and pressures at this location. The standard for FCCU's without add-on controls has been revised to allow sampling either upstream or downstream of the CO boiler. For FCCU's with add-on controls, the recommended location for SO_2 monitoring has been changed to downstream of the CO boiler.

1.1.7 Reduction in Reporting Requirements

This rulemaking provides the refiner with a standard for add-on control devices, an alternative standard for add-on control devices, a standard without add-on control devices, and a feed sulfur content cutoff. Initially, the refiner may elect to demonstrate compliance with any one of these standards and, at a later time, the refiner may elect to demonstrate compliance with one of the alternative standards. The standards were developed in this way to allow the refiner greater flexibility in compliance objectives but also to encourage the use of hydrotreating and SO_x reduction catalysts. The reporting and recordkeeping requirements for the proposed standards required that a refiner give a 90-day prior notification of his intent to be subject to a different standard and conduct a performance test with each change.

Since proposal, the EPA has changed the standards to require daily compliance determinations. This change requires an owner or operator to conduct performance tests every day regardless of the standard with which the owner or operator seeks to comply. The 90-day prior notification significantly reduces a refiner's flexibility without significantly increasing EPA's ability to enforce the standard. Therefore, the regulation has been changed so that prior notification is not required when the owner or operator seeks to comply with one of the other standards, regardless of whether the owner or operator has been subject to the particular standard previously. All changes must be identified in the next compliance report. Compliance reports are required quarterly, unless no exceedances have occurred during a particular quarter, in which case semiannual reports may be submitted. The proposal had not allowed semiannual reporting when there were periods of no exceedances. If an owner or operator elects to comply with an alternative SO_x standard, a quarterly report with notification of the change must be submitted to the Administrator in the quarter following such a change even if no violations of a standard have occurred.

1.1.8 Minor Changes

Several changes have been made to the SO_x emission percent reduction equation and SO_x emission rate equation such that direct results from the test methods can be used in the equations.

1.2 SUMMARY OF IMPACTS OF PROMULGATED ACTION

1.2.1 Environmental Impacts of Promulgated Action

Environmental impacts of the proposed standards are described in 49 FR 2058. The revisions to the proposed standards will have a minimal effect on the environmental impacts of the standards.

1.2.2 Energy and Economic Impacts of Promulgated Action

The energy and economic impacts of the standards are described in Chapters 6, 8, and 9 of the proposal background information document (BID). The energy impacts have not changed since proposal. The costs for sodium scrubbers have been revised; the cost and economic impacts of the final standards are greater than those calculated at proposal. The nationwide cumulative capital costs in the fifth year of these standards would be $117 million (reported in fourth quarter 1984 dollars), if sodium scrubbers are used at all facilities with feed sulfur levels above 0.30 percent by weight. The corresponding fifth year nationwide annual cost would be $45 million (reported in fourth quarter 1984 dollars). Fluid catalytic cracking units processing feeds with sulfur contents of 0.30 weight percent would be at the feed sulfur cutoff and therefore, would not need to install a scrubber. These nationwide cost estimates differ, therefore, from those presented in Tables A-10 and A-11 because costs for control of FCCU's with sulfur contents of 0.30 weight percent are not included here.

1.2.3 Other Considerations

1.2.3.1 Irreversible and Irretrievable Commitment of Resources. Implementation of these standards will result in the use of sodium-based scrubbers in many cases. This will necessitate the additional use of natural resources, especially sodium carbonate and sodium hydroxide. However, the commitment of these resources is expected to be small compared to national use.

1.2.3.2 Environmental and Energy Impacts of Delayed Standards. Delay in implementation of these standards would adversely impact air quality at the rate shown in Table 7-6 of the proposal BID. The annual "Sulfur Oxides Emissions Reduction" column in Table 7-6 represents the lost emission reductions for each year the standards are delayed. No adverse solid waste, water pollution, or energy impacts are expected from delaying regulatory action.

1.3 SUMMARY OF PUBLIC COMMENTS

Letters were received from 18 correspondents commenting on the proposed standards and the BID for the proposed standards, and from 12 correspondents commenting on the proposed revisions. There were no requests for a public hearing so none was held. A list of commenters, their affiliations, and the EPA docket numbers assigned to their correspondence are given in Table 1-1 of this document.

This document presents comments pertaining to the preamble and regulation resulting from the proposed standards. The comments from interested parties and EPA's responses to those comments have been categorized, and they are presented under the following topics:

- General Comments (Section 2)
- Control Technology Comments (Section 3)
- Environmental and Energy Impacts Comments (Section 4)
- Costs and Economic Impacts Comments (Section 5)
- Compliance Testing and Monitoring Comments (Section 6)
- Compliance Comments (Section 7)
- Modification/Reconstruction Comments (Section 8)
- Recordkeeping and Reporting Comments (Section 9)
- Miscellaneous Comments (Section 10)

TABLE 1-1. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR SULFUR OXIDES EMISSIONS FROM FCCU REGENERATORS

Commenter and Affiliation	Docket Item No.
1. Mr. J.A. Stuart South Coast Air Quality Management District 9150 Flair Drive El Monte, CA 91731	IV-D-1
2. Mr. J.J. Moon Phillips Petroleum Company 704 Phillips Building Bartlesville, OK 74004	IV-D-2
3. Mr. Phillip L. Youngblood Conoco, Incorporated P.O. Box 2197 Houston, TX 77252	IV-D-3
4. Ms. Gael Fletcher Koch Refining Company P.O. Box 43596 St. Paul, MN 55164	IV-D-4
5. Mr. R.V. Struebing Getty Oil Company P.O. Box 1650 Tulsa, OK 74102	IV-D-5
6. Mr. William F. O'Keefe American Petroleum Institute 1220 L Street, Northwest Washington, D.C. 20005	IV-D-6
7. Mr. Peter W. McCallum The Standard Oil Company Midland Building Cleveland, OH 44115-1098	IV-D-7
8. Mr. J.R. Bowler CITGO Petroleum Corporation Lake Charles Operations Box 1562 Lake Charles, LA 70602	IV-D-8
9. Mr. R.H. Murray Mobil Oil Corporation 3225 Gallows Road Fairfax, VA 22037	IV-D-9

TABLE 1-1. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR SULFUR OXIDES EMISSIONS FROM FCCU REGENERATORS

Commenter and Affiliation	Docket Item No.
10. Mr. J. Donald Annett Texaco, U.S.A. 1050 17th Street, N.W. Washington, D.C. 20036	IV-D-10
11. Mr. A.G. Smith Shell Oil Company P.O. Box 4320 Houston, TX 77210	IV-D-11
12. Mr. Michael J. Duffy Ashland Petroleum Company P.O. Box 391 Ashland, KY 41114	IV-D-12
13. Mr. L.G. Arnel Gulf Oil Products Company P.O. Box 2001 Houston, TX 77252	IV-D-13
14. Mr. J.M. Johnson Exxon Company, U.S.A. P.O. Box 2180 Houston, TX 77001	IV-D-14
15. Mr. A.R. Johnson Stone and Webster Engineering Corporation P.O. Box 2325 Boston, MA 02107	IV-D-15
16. Mr. Franklyn Isaacson 25 Summit Court Westfield, NJ 07090	IV-D-16
17. Mr. Bill Stewart Texas Air Control Board 6330 Highway 290 East Austin, TX 78723	IV-D-18
18. Mr. J.G. Huddle Amoco Oil Company P.O. Box 6110A Chicago, IL 60680	IV-D-20

TABLE 1-1. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR SULFUR OXIDES EMISSIONS FROM FCCU REGENERATORS

Commenter and Affiliation	Docket Item No.
19. Mr. Allan A. Griggs Diamond Shamrock P.O. Box 20267 San Antonio, TX 78220-0267	IV-K-1
20. Mr. Franklyn Isaacson 25 Summit Court Westfield, NJ 07090	IV-K-2
21. Mr. J.G. Huddle Amoco Oil Company P.O. Box 6110A Chicago, IL 60680	IV-K-3
22. Mr. M.J. Hage Mobil Oil Corporation 3225 Gallows Rd. Fairfax, VA 22037	IV-K-4
23. Mr. N.J. Wasilla SOHIO Midland Building Cleveland, OH 44115-1098	IV-K-5
24. Mr. J. Donald Annett Texaco, USA 1050 17th Street, N.W. Washington, D.C. 20036	IV-K-6
25. Mr. J.R. Bowler CITGO Petroleum Corporation Lake Charles Operations Box 1562 Lake Charles, LA 70602	IV-K-7
26. Mr. James H. O'Brien Lyondell Petrochemical Company 1200 Lawndale Box 2451 Houston, TX 77252-2451	IV-K-8
27. Mr. J.M. Johnson Exxon Company, U.S.A. P.O. Box 2180 Houston, TX 77001	IV-K-9

TABLE 1-1. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR SULFUR OXIDES EMISSIONS FROM FCCU REGENERATORS

Commenter and Affiliation	Docket Item No.
28. Mr. B.F. Ballard Phillips Petroleum Company Bartlesville, OK 74004	IV-K-10
29. Mr. J.A. Eslick Shell Oil Company One Shell Plaza P.O. Box 4320 Houston, TX 77210	IV-K-11
30. Mr. R.R. Kienle Shell Oil Company One Shell Plaza P.O. Box 4320 Houston, TX 77210	IV-K-12

2.0 GENERAL COMMENTS

2.1 NEED FOR THE STANDARDS

Comment:

Two commenters (IV-D-7 and IV-D-16) stated that the standards represent an unnecessary burden to the petroleum industry and, therefore, the standards should be withdrawn. The reasons cited by the commenters for withdrawal of the standards are: (1) other sources of SO_x could be controlled at a much lower cost per ton and (2) the SO_x emissions from FCCU's are insignificant when compared to the total SO_x emissions emitted in the United States.

Response:

Section 111 of the Clean Air Act directs the Administrator to list categories of stationary sources. The Administrator "... shall include a category of sources in such list if in his judgement it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Further, Section 111(a)(1) directs the Administrator to propose and promulgate standards of performance, which reflect the "best ... demonstrated" technology (BDT) for sources in this list.

Since passage of the Clean Air Act of 1970, considerable attention has been given to the development of an approach for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of EPA for implementing the Clean Air Act. Often, these areas of interest are actually pollutants emitted by stationary sources. Source categories that emit these pollutants are evaluated and ranked by a process involving such factors as: (1) the level of emission control (if any) already required by State regulations; (2) estimated levels of control that might be required from standards of performance for the source category; (3) projections of growth and replacement of existing facilities for the source category; and (4) the estimated incremental amount of air pollution that could be prevented in a preselected future year by standards of performance for the source category. Sources for which new source performance standards (NSPS) were promulgated or under development during 1977, or earlier, were selected using these criteria;

one of the source categories placed on the initial priority list was "Petroleum Refineries," of which FCCU's are a part.

Section 111(f), added by the Clean Air Act Amendments of 1977, now requires EPA to list major source categories. Major source categories are defined as those categories for which an average size plant has the potential to emit 100 tons or more per year of any one pollutant. This helps demonstrate the significance of the SO_x emissions from FCCU's because EPA has estimated that total SO_x emissions from new, modified, and reconstructed FCCU's in the fifth year (a total of 17 units) under Regulatory Alternative I (baseline emissions; i.e., emissions from the units if controlled under current regulations) would be 86,900 tons, an average emission rate of 5,100 tons/yr per FCCU. The standards reflect BDT and would reduce these total emissions by about 76,100 tons/yr; this reduction represents a significant improvement.

In summary, the standards of performance for SO_x emissions from FCCU's serve the intent of Section 111 of the Clean Air Act. Neither the ability to control other SO_x sources at a lower cost nor the percentage of total SO_x emissions emitted in the United States that are comprised by FCCU SO_x emissions negate the need for these standards.

Comment:

One commenter (IV-D-16) asked the following questions pertaining to the need for the standards with respect to prevention of significant deterioration (PSD) requirements which also regulate FCCU SO_x emissions:

(1) If each model source could yield considerably more than 250 tons per year of uncontrolled SO_x, the source is covered by the PSD requirements for best available control technology (BACT). Thus, if PSD will do the job, the proposed rules should be withdrawn. If not, the proposal BID and proposed rules should be reissued, with baseline emissions stated as those necessary to satisfy PSD BACT.

(2) If the 3.5 weight percent sulfur feedstock model plant is abandoned, the modeling results (proposal BID pages 7-4 through 7-7) show that unregulated FCCU's meet Class II and

III PSD, and primary and secondary national ambient air quality standard (NAAQS). Thus, there is no need for this NSPS.

(3) Since the SO_x discharges are above the small source tons per year limit, doesn't this trigger BACT, regardless of Class II or III increment?

Response:

Congress clearly understood that many sources subject to NSPS's would also be subject to PSD requirements, including BACT. Thus, the applicability of PSD does not show that the NSPS is not needed, as is discussed below. Petroleum refineries, of which FCCU's are a part, are listed in 40 CFR 52.21 (b)(1)(i)(a) as a "major stationary source" (i.e., a stationary source of air pollutants which emits, or has a potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Clean Air Act). Therefore, a new, modified, or reconstructed FCCU would be subject to PSD requirements if the unit is located in an SO_2 attainment area and if the emissions from the FCCU will not affect the SO_2 levels in an area that is designated as attainment for SO_2. Depending on the classification of the attainment or unclassified area (Class I, II, or III), a maximum allowable increase of the ambient air baseline concentration is specified for that area [40 CFR 52.21(c)]. The maximum allowable increase will be less than that specified if the specified increase will raise the ambient air concentration above the NAAQS. If this situation occurs, the maximum allowable increase will equal an increase that would cause the ambient air concentration to equal the NAAQS. [Note: The EPA expects that no FCCU would be located in a Class I area (pristine environment) and there are no Class III areas.] The baseline concentration is established on the earliest date after August 7, 1977, on which the first complete application under 40 CFR 52.21 was submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21. After that date, each net emissions increase by sources in the area reduces, by the same amount, the maximum allowable emissions increase for that area.

The current allowable emissions increase helps determine the emission limitation under which the source may operate; that is, the source will be subject to BACT. The term BACT, as defined in 40 CFR 169(3), means "... an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from, or which results from, any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant." However, the entire allowable emissions increase may or may not be available for use by the source. Several other constraints will influence the amount of emissions the source will be allowed to emit; these constraints are unemployment conditions, attractiveness of the source (the area's desire for that industry), other sources wanting to locate in the area, etc. After all variables are taken into considderation, BACT is then determined.

There are no specified levels of BACT; each BACT determination is dependent on the constraints within the area (i.e., BACT is determined on a case-by-case basis). If an area was interested in having an industry locate in its region and there was a substantially large allowable emissions increase available, the source could receive a rather lenient BACT determination. Due to budget limitations, many States are not able to conduct thorough BACT investigations without relying upon the NSPS program. At this point, the NSPS program provides an integral part of the BACT determinations process. The development of NSPS follows the same course as the development of BACT without the additional constraints that could be imposed on the BACT determination process. As such, NSPS provides the baseline from which BACT is developed. BACT could be more stringent than NSPS, however, as stated in 40 CFR 169(3) "... in no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Sections 111 or 112 of this Act." In summary, PSD/BACT requirements do not preclude the need for NSPS; rather, NSPS defines the maximum emission level that BACT can allow.

2.2 REGULATED POLLUTANT

In the proposed revisions (50 FR 46464), the Agency proposed to change the regulated pollutant from SO_x to SO_2 for the standard with add-on controls, but keep SO_x as the regulated pollutant for the standard without add-on controls. Comments were received only on the proposed decision to keep SO_x as the regulated pollutant for the standard without add-on controls. These comments and the Agency's responses follow.

Comment:

Several commenters (IV-K-2, IV-K-6, and IV-K-8) suggested that EPA use SO_2 rather than SO_x as the regulated pollutant for the standard for SO_x reduction catalysts. One commenter (IV-K-2) stated that other refinery sources are only regulated for SO_2 and that EPA usually regulated only SO_2. This commenter questioned how an opacity standard tested with an in-stack monitor could limit the emissions of SO_3. According to the commenter, although SO_3 condenses to acid mist upon contact with the atmosphere, the continuous monitors approved by EPA are stack-mounted and monitor emissions before any atmospheric contact occurs.

In another comment letter (IV-D-16), Commenter IV-K-2 stated several points pertaining to the SO_3 component of the FCCU flue gas:

(1) The Federal Register notice claims that oxygen content may substantially increase the SO_3 content of FCCU flue gas. Although oxygen drives the reaction to sulfur trioxide, it is only to the 0.5 power of oxygen content. Thus, the effect is less than linear.

(2) SO_3 typically is greater than 10 percent of the total SO_x emissions. This statement is based on test data reported in the proposal BID and on the commenter's experience in the refining industry.

(3) SO_x reduction catalysts work best when the regenerator operates to maximize the fraction leaving as SO_3.

Another commenter (IV-K-6) stated that preliminary data previously submitted to EPA from several SO_x reduction catalyst trials at one of their refineries indicate the SO_x emissions have generally contained only an insignificant amount of SO_3. (This commenter noted that the same result was also found without the use of SO_x reduction catalysts.)

Commenter IV-K-8 stated that by using SO_2 as the regulated pollutant (1) the same monitoring technique (proven SO_2 monitors) would be used as is for add-on scrubber technology and (2) cost savings and consistency and reliability of the sample results would be gained. This commenter also stated that emerging SO_x reduction catalyst data indicate that SO_3 is unaffected by the catalysts; SO_x reduction catalysts control SO_2, while allowing the percent, but not the total amount of SO_3 to increase; and, therefore, SO_x reduction catalysts do not create a large excess of SO_3.

Response:

The Agency has considered the arguments presented by the commenters and reviewed the data available on the composition of SO_x when using SO_x reduction catalysts. After this review, the Agency still believes that the most appropriate regulated pollutant for SO_x reduction catalysts is SO_x, not SO_2.

The Agency recontacted SO_x reduction catalyst vendors to review the mechanism by which SO_x reduction catalysts reduce total SO_x emissions (see Docket Nos. IV-E-19 and IV-E-20). Contrary to what Commenter IV-K-8 states, the SO_x reduction catalyst vendors indicate that SO_x reduction catalysts preferentially remove SO_3, forming a metal sulfate compound that is much more stable than the metal sulfite compound formed when the SO_2 reacts with the catalyst. As the SO_x reduction catalyst picks up more and more SO_3, the equilibrium balance is disturbed. To regain equilibrium, more SO_2 becomes SO_3. If the rate of SO_2 to SO_3 is less than the rate of metal sulfate formation (SO_3 plus metal oxide), then the SO_3 percentage in the FCCU emissions will decrease. On the other hand, if the SO_2 to SO_3 rate is faster than the metal sulfate formation rate, then this SO_3 percentage will increase. To ensure maximum SO_x removal efficiency, the owner or operator would likely operate a regenerator, to the extent possible, in such a manner that the SO_2 to SO_3 rate is not limiting; that is, create conditions within the regenerator that increase the SO_3 percentage.

The Agency again reviewed the data on SO_2/SO_3 in regenerator emissions, including that submitted by Commenters IV-K-6 and IV-K-8. The Agency requested in the revised proposal that any data that were available on this be submitted. Very little data were submitted.

The data base remains very limited and inconclusive. The Agency agrees that the more recent data generally tend to have a lower percentage of SO_3 than the earlier data. Some of the recent data still suggest, however, that there is a potential for large amounts of SO_3 to be emitted, which would be undetected by a standard using SO_2 as the regulated pollutant. Thus, regulating SO_2 only will not necessarily reflect the potential control of SO_x that can be obtained by SO_x reduction catalysts.

The Agency agrees with Commenter IV-K-2 that transmissometers would not measure uncondensed SO_3 emissions in the stack. Opacity compliance determinations, however, are made through visible emissions reading of the plume opacity. Transmissometers are intended to show proper operation and maintenance of the particulate control device. Some information is available that indicates plume opacity is higher than in-stack opacity when higher sulfur fuels are burned. Thus, it is the plume opacity that is affected by the condensation of SO_3 and, to the extent this condensation affects the ability of a source to comply with the (plume) opacity standard, it may also help limit the emissions of SO_3. The Agency requested, but did not receive, data on this possibility. If sufficient data had been presented, then the Agency would have considered changing the regulated pollutant for FCCU's without add-on controls from SO_x to SO_2 so that SO_2 CEMS's could be used for compliance determinations.

The Agency agrees that using SO_2 as the regulated pollutant would allow the same monitoring technique to be used as for add-on controls and that cost savings would likely be gained. However, the Agency is not having an SO_2 standard for FCCU's without add-on controls, and using SO_2 CEMS's will not necessarily yield more consistent and reliable sample results than would keeping an SO_x standard and using Method 8 sampling. There is no need or requirement that the same monitoring technique be applied to alternative standards. Each possible monitoring technique is evaluated on its own merit. The facts raised by Commenter IV-K-2 that other refinery sources are regulated only for SO_2 and that EPA usually regulated only SO_2 shed no light on whether an SO_x standard is appropriate for this source.

2.3 DESIGNATION OF AFFECTED FACILITY

Comment:

Several commenters (IV-D-1, IV-D-15, and IV-D-16) recommended a broadening of the designation of the affected facility. Two commenters (IV-D-1 and IV-D-15) stated that the FCCU reactor should be included as part of the affected facility because of the dependency between the reactor and regenerator. One commenter (IV-D-15) suggested that, for an FCCU reactor using multiple regenerators, the affected facility should include the reactor and all of the regenerators serving the reactor, because it may be possible that SO_x control systems used on multiple regenerator systems are more efficient. Another commenter (IV-D-16) recommended that the affected facility should include the FCCU reactor, fractionator, and gas recovery unit. The commenter stated that hydrocarbon streams recycled from the fractionator or gas recovery unit are defined as "fresh feed" to the affected facility. Therefore, by increasing the amount of these low sulfur streams recycled to the FCCU reactor, a refiner could circumvent the intent of the feed sulfur cutoff, because it would be easier to maintain a feedstock sulfur content below the 0.30 weight percent sulfur level by recycling these.

Response:

The rationale for selection of the affected facility was presented in the preamble to the proposed standards (49 FR 2060). As stated in the preamble, SO_x are generated in and emitted from the FCCU regenerator. The designation of the regenerator of each FCCU as the affected facility, rather than the entire FCCU, would lead to bringing replacement equipment under these standards sooner and thus, would adhere to the purpose of Section 111 of the Clean Air Act.

The EPA agrees that identifying each FCCU regenerator as the affected facility for multiple regenerator configurations is unreasonable. If only one regenerator in a multiple regenerator configuration were to become subject to the standards, it would be impossible in some multiple regenerator ducting arrangements to isolate and measure the SO_x content of the exhaust gases from the affected regenerator. Furthermore, because the refiner would want to minimize the cost and downtime for revamping work on the unit, it is unlikely that only one regenerator in a multiple regenerator configuration would be modified or reconstructed without the others. Therefore, the affected facility is now defined to include all regenerators serving an FCCU reactor.

The proposed definition of "fresh feed" specifically excluded those petroleum derivatives recycled within the FCCU. To ensure that a refiner would not circumvent the feed sulfur cutoff by adding low-sulfur content recycle from the fractionator and gas recovery unit, EPA has revised the definition of "fresh feed" in the regulation. The revised definition specifically identifies petroleum derivatives from the FCCU, fractionator, and gas recovery unit as recycle, and thus excludes them from the definition of "fresh feed."

Comment:

One commenter (IV-D-12) stated that the proposed standards should not apply to Reduced Crude Conversion (RCC) processes or Asphalt Residual Treatment (ART) units. The following justification was provided:

1. An FCCU processes clean gas oils while the commenter's RCC unit processes asphalt-containing long residuum (reduced crude), which has heavy metal constituents, high carbon residue, and higher sulfur content. Consequently, RCC units may have a very different catalyst design.
2. The refining objective for an RCC unit (residual upgrading) is different from an FCCU processing distillate oils.
3. The ART process employs an adsorbent rather than a cracking catalyst.
4. The ART process objective is minimal change in the feedstock other than metals removal. It is a feedstock upgrading process.
5. The ART and RCC units are operated under conditions critical to residual upgrading. These units are designed and operated to avoid undesirable secondary reactions. Control of heat release is accomplished by multiple stage regeneration, limited carbon burn, and catalyst heat exchange.

Response:

To upgrade residual feedstocks and to increase gasoline and middle distillate product yields, new processes termed heavy oil cracking (HOC), which includes RCC, and ART are being installed at refineries. The HOC units are FCCU's that process residual and other heavy oil feedstocks. As in a conventional FCCU, emissions occur as a result of catalyst regeneration. Emissions of SO_x may, in fact, be greater from

HOC units than from other FCCU's because HOC feedstocks have a higher coke make rate than gas oil feeds, and because a greater portion of the sulfur in HOC feedstocks forms coke than that in gas oil feeds. The EPA's analysis of SO_x emissions, control costs, and cost effectiveness for HOC units showed that the proposed standards for FCCU's are achievable and affordable for HOC units. The results of this analysis were presented in Appendix F of the proposal BID.

Emissions, emission control, and control costs for the ART process were further evaluated by EPA (see Docket A-79-09, item IV-B-17). The differences stated by the commenter between an ART unit and an FCCU do exist. The ART process does not employ a catalyst, but rather uses an inert microspheric contact material that collects contaminants. The objective of the ART process is feedstock upgrading, not processing, and some of the operating conditions may vary significantly.

Nevertheless, important similarities in regenerator configuration, operation, and emissions exist that warrant the regulation of an ART unit under the FCCU NSPS. For both an ART unit and a conventional FCCU, regeneration is performed to burn off coke from the catalyst or contact material, thereby restoring it for reuse in the unit. Opacity and emissions of CO, SO_x, and particulate from an ART unit regenerator during normal operation are expected to be within the range of emissions from all types of FCCU regenerators, including those on HOC's. The EPA evaluated control feasibility and cost for an ART unit based on reported emissions (see Docket A-79-09, item IV-D-30), and determined that control of an ART unit by a scrubber was applicable and had a reasonable cost. Based on a scrubber SO_x efficiency of 90 percent, the scrubber cost effectiveness calculated for the ART unit is below the range of cost effectiveness expected for FCCU's. In addition, costs to control CO emissions, if necessary, and particulate emissions are estimated to be reasonable.

The similarity in emissions from the regenerator and the availability of control equipment at a reasonable cost indicate that the ART unit regenerator can meet the FCCU standards. The facts that the objective of the ART process is different than that of the FCCU and that the material being regenerated is not a catalyst are not significant reasons to support the contention that an ART unit should not be subject to the FCCU NSPS. Therefore, the proposed standards covered both

ART and HOC units and the promulgated standards continue to require that an ART unit, HOC, or any other similar type of fluidized bed treatment unit regenerator achieve the FCCU particulate, opacity, CO, and SO_x standards.

2.4 FORMAT OF THE STANDARDS

Comment:

Several commenters (IV-D-3, IV-D-10, IV-D-11, IV-D-14, and IV-K-12) stated that EPA should establish a single SO_x standard for FCCU's. The reasons cited by the commenters for setting a single standard are: (1) a single standard would allow refiners the options and flexibility of determining the most cost-effective method of meeting that limit; and (2) a single standard would comply with Section 111(h) of the Clean Air Act which implies that the Administrator should prescribe a performance standard rather than a work practice or equipment standard, where feasible to do so.

Response:

There are three techniques applicable to control FCCU SO_x emissions: (1) scrubbing of FCCU regenerator exhaust gases; (2) using SO_x reduction catalysts; and (3) using low sulfur FCCU feedstocks obtained by feedstock hydrotreating or from naturally occurring low sulfur crude oils. The Clean Air Act requires EPA to develop standards of performance for new, modified, and reconstructed FCCU regenerators that reflect the best method of continuous emission reduction, considering costs, environmental, energy, and nonair quality health impacts.

To develop SO_x emission standards for FCCU's, EPA evaluated all available techniques for controlling FCCU SO_x emissions. Upon thorough consideration of the availability, SO_x emission reduction capability, and impacts associated with each of these techniques, EPA determined that scrubbing systems effectively control SO_x emissions from all types of FCCU applications, and represent BDT for FCCU SO_x and SO_2 emissions. However, for many FCCU applications, SO_x emissions can be reduced effectively by using SO_x reduction catalysts or by using low sulfur FCCU feedstocks obtained by either hydrotreating high sulfur feedstocks or processing naturally occurring low sulfur crude oils. For the sources that can effectively and continuously reduce SO_x emissions without the use of add-on controls, EPA concluded it is reasonable to establish alternative standards.

The standard for add-on controls requires that the control device achieve a 90 percent reduction in SO_2 emissions. The percent reduction format was selected because it best reflects the performance of add-on controls for all expected feed sulfur levels. This is consistent with Section 111(a)(1), which requires that the standard reflect...application of BDT. A standard without add-on controls also was established to allow refiners the flexibility to use SO_x reduction catalysts, low sulfur feedstocks, or a combination of both techniques. Although these techniques may be less effective at reducing SO_x emissions than scrubbers for some FCCU applications, they have lower costs and smaller nonair environmental impacts when compared to using a scrubber. The EPA judged that it is reasonable to give up some emission reduction by establishing a standard without add-on controls in return for the other benefits afforded by using SO_x reduction catalysts, hydrotreating, or low sulfur feedstocks instead of scrubbers. If a refiner believes that using SO_x reduction catalysts, hydrotreating, or low sulfur feedstocks for his particular FCCU application will not achieve the standard without add-on controls, then the refiner can still install and operate an add-on control device that achieves 90 percent reduction of SO_2 emissions.

The standards are performance standards and are consistent with Section 111 of the Clean Air Act. Neither the add-on control standard nor the standard for FCCU's without add-on controls specifies the type of controls that must be used or exactly how the controls are to be operated to achieve the standard.

Comment:

Several commenters (IV-D-2, IV-D-3, IV-D-10, and IV-D-11) stated that the percent reduction format proposed by EPA for the standard with add-on controls should be changed to an emission limit format. An emission limit standard would simplify compliance and would allow a refiner to control SO_x emissions to a specific level rather than a percent reduction, which is a moving target.

Response:

Compliance with the percent reduction format requires conducting a performance source test at both the inlet and outlet of the control device. The EPA agrees that an emission limit format for the standard for add-on controls would simplify compliance procedures by requiring source testing only at the control device outlet. However, this format would not reflect the best level of control achievable by scrubbers. As discussed above, 90 percent reduction represents BDT. An emission limit format could result in greater emissions. A refiner may perceive the percent reduction format to be a "moving target" because with a percent reduction format there is no specific emission level that is to be achieved at the control device outlet. Rather, the outlet emission level will vary depending on the inlet concentration to the control device. The proposed monitoring requirements that specified a control device outlet SO_2 monitor only may have contributed to the commenters' opinion that it is difficult to operate a control device to achieve a constant percent reduction. With only a scrubber outlet SO_2 monitor, the refiner had no means of monitoring the percent reduction achieved by the control device. The EPA has changed the monitoring requirements and continuous SO_2 monitors now are required at the inlet and outlet to the control device (see Section 6.2). Consequently the refiner will have the monitoring results available to determine the percent reduction achieved by the control device. The percent reduction, calculated by using the continuous monitoring results, thus becomes a fixed rather than a moving target for refiners to achieve.

Comment:

Three commenters stated that the coke burn-off format proposed by EPA for the standard for FCCU's without add-on controls is inappropriate. One commenter (IV-D-9) stated that the coke burn-off format allows no latitude for variation in coke sulfur content and will discourage process improvements. The format penalizes refiners who implement process improvements that increase yields of light products while reducing coke make because allowable emissions will be reduced, perhaps to an unachievable level. The commenter suggested that EPA consider a sliding scale format that allows for variation in coke sulfur content. A second commenter (IV-D-1) stated that the coke burn-off format was considered during the development of the South Coast Air Quality Management District (SCAQMD) Rule 1105, but it was concluded that this format was inappropriate because coke burn-off rates are not normally recorded and can change significantly. Instead of a coke burn-off format, the SCAQMD rule uses a format expressed in terms of kilograms of SO_2 per thousand barrels of feed. A third commenter (IV-D-8) stated that a percent reduction format should be adopted rather than a nonflexible limit of sulfur on coke.

Response:

Based on a sensitivity analysis presented in Appendix F of the proposal BID, EPA concluded that the coke burn-off format relates well to normal fluctuations in SO_x emissions from FCCU's processing a variety of feeds. This is because SO_x emissions are related directly to the coke sulfur content. Normally, FCCU's are operated to limit the amount of coke that can be burned off in the regenerator. Process improvements that reduce the coke make rate are made to allow the refiner to process more feed through the unit until the unit is again limited in the amount of coke it can burn off. An example of a process improvement that results in reduced coke make is high temperature regeneration (HTR). The initial result of HTR would be reduced SO_x emissions from FCCU's on a mass basis. However, SO_x emissions in terms of coke burn-off would remain the same because SO_x emissions are related to the sulfur on coke. Thus, the refiner could increase throughput until the unit is again coke burn-off limited and still be within the standard even though emissions would increase. This format offers greater refining flexibility than a mass of SO_x per unit of feed basis. The commenters provided no new information to refute this conclusion.

A sliding scale format that allows for variation in coke sulfur content would be difficult to enforce because the sulfur content of the coke on catalyst is not readily obtainable. For this reason, EPA considers a sliding scale format unreasonable.

The EPA considered a percent reduction format for the standard for FCCU's without add-on controls. This format would require the SO_x reduction catalyst to reduce FCCU emissions by a set percentage. The EPA did not select a percent reduction format because of compliance considerations. With SO_x reduction catalysts, there is no uncontrolled or inlet SO_x concentration to measure. Thus, it would be impossible to determine through stack testing the percent reduction being achieved by the catalysts. An alternative method would be to estimate the percent reduction achieved by SO_x reduction catalysts using EPA's correlation for feed sulfur and SO_x emissions. However, EPA's correlation represents an average for all FCCU's and feedstocks. While the correlation is useful for analyzing the overall impact of the standards, inlet SO_x concentrations may be lower or higher than the level predicted by the correlation for a specific FCCU and feedstock. Thus, the correlation cannot be used on a case-by-case basis. The cost to develop a separate correlation for each feedstock and FCCU affected by the standards is unreasonable. Therefore, EPA concluded that use of a correlation for determining potential uncontrolled SO_x emissions is not practical. Because there is not a practical method for determining the SO_x inlet concentration when using SO_x reduction catalysts, EPA did not select a percent reduction format.

The EPA considers the coke burn-off format reasonable because of its direct relationship to the sulfur-on-coke relationship. The coke burn-off format is identical to the format selected for the NSPS particulate standard; the coke burn-off rate can be recorded reasonably and would be readily available.

2.5 LEVEL OF STANDARDS

2.5.1 Level for Add-On Control Standard

Comment:

Two commenters (IV-D-2 and IV-D-4) questioned the level of the standard for add-on controls. One commenter (IV-D-4) stated that the standard for add-on controls is excessively stringent. Another commenter (IV-D-2) stated that the standard for add-on controls should be 300 vppm rather than 50 vppm because a 300 vppm standard is approximately equivalent to a 90 percent SO_x reduction for most FCCU applications. In contrast, three commenters (IV-D-1, IV-D-11, and IV-D-18) stated that the standard is reasonable. One commenter (IV-D-11) stated that BDT for add-on controls at 90 percent by weight reduction (or 50 vppm) is achievable. Another commenter (IV-D-18) stated that the options provided for achieving compliance with the proposed standards are realistic when analyzed in terms of existing industry processing and emission control practices.

Response:

The standard for add-on controls requires that FCCU SO_2 emissions are reduced by 90 percent or to 50 vppm, whichever is less stringent. The standard is based on test data that demonstrate that scrubbers can achieve 90 percent reductions in FCCU SO_x emissions. The 50 vppm outlet concentration level was established because scrubber SO_x removal efficiency tends to decrease at low inlet SO_x concentrations (see Section 3.1 of this document). Therefore, the 50 vppm level is not intended to compare with the 90 percent level for most cases.

The EPA disagrees that a 300 vppm standard is equivalent to 90 percent reductions for most FCCU applications. Most FCCU's are processing feedstocks with sulfur contents ranging from 0.3 to 2 percent by weight, with corresponding uncontrolled SO_x emissions ranging from 300 to 2,000 vppm. Fluid catalytic cracking unit SO_x emissions when controlled by scrubbers would range from 50 to 200 vppm. Thus, a 300 vppm SO_x emission standard would not compare to 90 percent reduction in most cases. In summary, a 300 vppm standard does not represent the level achievable by application of BDT and, therefore, was not selected as the level for the standard for add-on controls.

2.5.2 Level of Standard for FCCU's Without Add-On Controls

Comment:

Seven commenters (IV-D-2, IV-D-3, IV-D-6, IV-D-7, IV-D-8, IV-D-9, and IV-D-10) stated that the standard for FCCU's without add-on controls should be set at 13 kg SO_x/1,000 kg coke burn-off because: (1) increasing the level to 13 kg SO_x/1,000 kg coke burn-off would have a limited impact on ambient air quality; (2) 80 percent reductions by SO_x reduction catalysts are not supported by the limited commercial tests cited by EPA; and (3) a 13 kg SO_x/1,000 kg coke burn-off emission limit would allow more refiners to use the catalysts rather than add-on controls since SO_x reduction catalysts are the only cost-effective and environmentally acceptable control alternative. Two commenters (IV-D-6 and IV-D-10) added that an increase in the emission limit should be made to account for the change in the controlled pollutant from SO_2 to SO_x. In contrast, two commenters (IV-D-1 and IV-D-18) supported the levels proposed by EPA. One commenter (IV-D-1) reported that Phase II of the SCAQMD Rule 1105 is more stringent than the standard. The commenter stated that SO_x reduction catalysts are expected to be used to meet Phase II of the rule. Another commenter (IV-D-18) stated that the emission reduction required by the standard is essentially equivalent to the level of control required by the Texas Air Control Board (TACB) to control FCCU SO_x emissions.

Response:

The EPA disagrees with the comment that SO_x reduction catalysts are the only cost-effective and environmentally acceptable control alternative. The EPA determined, considering costs, environmental, energy, and nonair quality health impacts, that scrubbers effectively control FCCU SO_x emissions and are BDT. Furthermore, as an alternative to using SO_x reduction catalysts, refiners may use hydrotreating or low sulfur feedstocks to achieve compliance with the 9.8 kg SO_x/1,000 kg coke burn-off level.

The level of the standard (9.8 kg SO_x/1,000 kg coke burn-off) was selected to allow refiners flexibility to use SO_x reduction catalysts with best currently available performance, and to encourage the further development of the catalyst technology. For many feedstocks, especially those with lower sulfur content, the emission reduction needed to achieve the level of the standard is less than 80 percent. For example, a feedstock with 0.5 weight percent sulfur would need approximately 50 percent reduction in SO_x emissions to achieve the level of the standard. In response to the comments, EPA contacted a number of companies known to be developing SO_x reduction catalysts to request updated information on the performance and availability of developmental SO_x reduction catalysts. Based on a survey of SO_x reduction catalyst developers, current commercial SO_x reduction catalyst test data have been reported by the developers to reduce FCCU SO_x emissions by 65 to 75 percent. The test data reported by the developers span a wide range of catalyst performance; some data points show catalyst performance as high as 90 percent. As the technology continues to develop, refiners will be able to use the catalyst technology to achieve the standard for a greater range of feedstocks.

Based on the results of SO_x reduction catalyst tests, EPA believes the level of the standard for FCCU's without add-on controls is reasonable. The determination of the level of this standard included consideration of the benefits of SO_x reduction catalysts and the increase in SO_x emissions compared to the BDT of scrubbing. Because the primary purpose of the standards is to reduce future FCCU SO_x emissions, and scrubbers can achieve cost-effective emission reductions, EPA concluded that it is not reasonable to further increase allowable emissions by raising the level of the standard.

The EPA proposed standards regulating total FCCU SO_x emissions because SO_3 can comprise a substantial portion of the FCCU SO_x emissions when SO_x reduction catalysts are used, and the potential SO_x emissions from FCCU regenerators can be significant. Both SO_2 and SO_3 are emitted from FCCU regenerators. Data from source tests indicate that SO_3 usually comprises less than 10 percent of the total SO_x emissions. However, with high excess air and certain types of catalysts or catalyst additives, SO_3 can comprise a substantial portion (up to 60 percent) of the total SO_x emissions. The SO_x reduction catalyst data used by EPA to select the level of the standard are reported in terms of total SO_x emissions. Thus, EPA's choice for the level of the standard took into consideration that the controlled pollutant is SO_x instead of SO_2.

2.5.3 Feed Sulfur Cutoff

Comment:

Two commenters (IV-D-4 and IV-D-11) stated that an arbitrary feed sulfur cutoff of 0.30 weight percent sulfur is too restrictive. One commenter (IV-D-11) wrote that a feed sulfur cutoff equivalent to 9.8 kg SO_x/1,000 kg coke burn-off should be established. This would be accomplished by developing a correlation between feed sulfur content and SO_x production using test data.

Response:

The selection of the feed sulfur cutoff level of 0.30 weight percent was not arbitrary. As was discussed in the preamble to the proposed standards, the feed sulfur cutoff level was selected based on consideration of the costs for application of scrubbers to control SO_x emissions from FCCU's processing low sulfur feedstocks, and the feedstock sulfur levels refiners are expected to be processing if they elect to use naturally occurring low sulfur feed or to hydrotreat high sulfur feeds.

A correlation between FCCU feed sulfur content and SO_x emissions is presented on p. 3-18 of the proposal BID. The correlation is based on test data for a large number of FCCU's and feedstock types. Based on this correlation, an FCCU SO_x emission level of 9.8 kg SO_x/1,000 kg coke burn-off corresponds to a feed sulfur level of approximately 0.3 weight percent. Thus, the feed sulfur cutoff level established by EPA is approximately equivalent to the standard for FCCU's without add-on controls. There is no need for each refiner to determine, on a case-by-case basis, a correlation between feed sulfur content and SO_x production.

2.6 AVERAGING TIMES

Comment:

Commenters (IV-D-2, IV-D-3, IV-D-4, IV-D-6, IV-D-10, IV-D-11, and IV-D-20) stated that the averaging time for the standards should be increased. Several of these commenters (IV-D-3, IV-D-6, IV-D-10, and IV-D-11) stated that a 7-day averaging period for compliance would be appropriate for the standards for add-on controls and for FCCU's without add-on controls for the following reasons: (1) a 7-day averaging time would be consistent with the averaging time for the feed sulfur cutoff; (2) no process variables can be adjusted in a 3-hour period to regulate SO_2 emissions when using SO_x reduction catalysts; and (3) 7 days would account for variation in SO_2 inlet concentrations to the control device whereas 3 hours would not. Another commenter (IV-D-2) stated that the excess emissions averaging times should be lengthened to 7 days for the same variability reasons. One of the commenters (IV-D-11) stated that the averaging period for compliance determinations should be set at 7 days with daily peaks not exceeding 13 kg SO_x/1,000 kg coke burn-off. Two commenters (IV-D-4 and IV-D-20) stated that the averaging period for the add-on control and 9.8 kg/1,000 kg coke burn-off standards should be a rolling 30-day period.

Response:

Upon evaluation of the comments on variability, EPA agreed with the commenters that the averaging time for compliance with the standards for FCCU's with and without add-on controls should be lengthened. The EPA assessed long-term variability by statistically analyzing the continuous SO_2 monitoring data from an EPA study of a sodium scrubber applied to an FCCU (see Docket A-79-09, item IV-B-5). Several of the commenters pointed to this study as an example of the potential variability in scrubber inlet conditions due to variability in FCCU operation and feedstocks. The hourly percent reductions achieved by the scrubber were used in a time series analysis to compare various averaging times. For a given averaging time, the time series model estimated the minimum scrubber performance level that would be expected once in 10 years.

The results of this analysis showed that 3 hours is too short to ensure that exceedances of the standard would not occur due to normal variability. However, with a 7-day rolling average, the minimum performance level estimated once in 10 years was greater than the level of the standard. This result indicates that 7 days would adequately account for normal variability in scrubber performance.

Because the SO_x reduction catalyst technology is still in the developmental stages, there were no tests that were appropriate to use for long-term analysis. However, EPA agreed with the comment that 7 days would allow a reasonable amount of time to adjust process variables after such changes as to a different feedstock, whereas 3 hours would be too short. Therefore, EPA concluded that a 7-day averaging time would be reasonable for both the standards for add-on controls and for FCCU's without add-on controls. The EPA did not choose a longer time because 7 days is long enough to eliminate exceedances of the standard due to normal variation. The revised proposed standards included a revision of the compliance averaging time from 3 hours to 7 days. Six commenters (IV-K-1, IV-K-3, IV-K-5, IV-K-6, IV-K-9, and IV-K-10) all agreed with EPA's revision. No commenters disagreed.

Comment:

Two commenters (IV-D-4 and IV-D-20) stated that the averaging period for the feed sulfur cutoff should be a 30-day rolling average period. The use of the 30-day period would be appropriate because a 30-day rolling average period is used for the fossil fuel-fired steam generator NSPS.

Response:

Whenever practical, EPA determines NSPS regulatory requirements on an individual source category basis. It is not appropriate to use a 30-day rolling average period for the FCCU feed sulfur cutoff standard simply to copy the fossil fuel-fired steam generator NSPS. The proposed 7-day averaging period was selected by EPA after careful consideration of a range of averaging periods. A daily averaging time was judged by EPA to be too short to account for sampling variability. Also, a daily averaging time would constrain a refiner's flexibility in blending different types of feedstocks for processing in the FCCU. A 7-day averaging time would reduce sampling variability and increase refiner flexibility in selecting the FCCU feedstock mix. However, increasing the averaging time beyond a 7-day period would allow feedstocks with sulfur contents significantly greater than 0.30 weight percent to be processed in the FCCU during a portion of the sampling period. Consequently, a refiner would be able to process high sulfur feedstocks without having to use any SO_x controls. Therefore, EPA selected the 7-day averaging period to allow reasonable flexibility to the refiner for processing different sulfur content feedstocks.

3.0 CONTROL TECHNOLOGY COMMENTS

3.1 SO_x SCRUBBERS

Comment:

Two commenters (IV-D-5 and IV-D-9) challenged EPA's assessment of the performance of scrubbers as applied to FCCU's. They stated that the proposed standard for add-on controls is founded upon an insufficient data base; that scrubber performance on FCCU's processing higher sulfur feeds (2 percent or more sulfur) should be confirmed. One commenter (IV-D-9) wrote that there can be subtle differences among scrubber feeds and chemical constituents containing sulfur that affect scrubber removal efficiencies. Thus, scrubber performance for boilers firing high sulfur coal differs from scrubber performance for FCCU's processing high sulfur feedstocks.

Response:

Scrubber SO_x control is a function of the scrubbing liquor sorbent and good contacting between the SO_x-containing flue gas and the scrubbing liquor. Based on engineering judgment, scrubbers applied to higher SO_x-containing gas streams would be expected to operate as well as those scrubbers applied to lower SO_x-containing gas streams. However, because scrubbers have not been applied to FCCU's processing high sulfur feeds, none was available for testing by EPA to confirm scrubber performance. Therefore, EPA compared the composition of FCCU exhaust gases to industrial boiler flue gases to determine if the performance of sodium scrubbers for industrial boilers is applicable to FCCU's processing high sulfur feedstocks. This comparison showed that the coke formed on the FCCU catalyst is a carbonaceous material similar to the coal used in solid fuel-fired industrial boilers. The catalyst coke is burned off the catalyst during regeneration by adding air to the regenerator. The regeneration process is thus similar to the combustion processes that take place in boilers. Given the similarities between catalyst coke and other solid fuels, the combustion process that takes place in the FCCU regenerator is expected to yield exhaust gases that are similar to those derived from coal-fired boilers. A comparison between FCCU regenerator exhaust gases and industrial boiler flue gases was presented in Table 4-3 in the proposal BID. The comparison showed that the ranges in concentration of most FCCU regenerator exhaust gas constituents [nitrogen (N_2), oxygen (O_2), CO_2, SO_x, nitrous oxides (NO_x)] are similar to the boiler flue gas concentrations. Scrubber systems installed on FCCU regenerators will thus experience similar inlet concentrations as boiler scrubber systems. The primary difference between FCCU regenerator exhaust gases and boiler flue gases is the particulate emissions. Boiler particulate emissions are higher and composed primarily of fly ash. Catalyst fines comprise the majority of regenerator particulate emissions. In an industrial boiler application, fly ash is typically collected upstream of a non-venturi type scrubber. A similar type of scrubber applied to an FCCU would require particulate control upstream from the scrubber. According to scrubber vendors (refer to Docket A-79-09, item IV-J-6), the particulates that pass through the particulate control device would not affect the design of the scrubber regardless of the application. This is because catalyst fines are no more erosive than fly ash and neither type of particulate would interfere with the scrubbing reaction. Thus, the difference in particulates from an industrial boiler and an FCCU are not expected to affect scrubber performance. Hydrocarbon emissions from FCCU regenerators may be higher than those from boilers. The presence of hydrocarbons in the FCCU gas stream will not affect scrubber operation or performance. Due to the low solubility of hydrocarbons in the aqueous scrubbing liquor, the hydrocarbons will not be absorbed but pass through the scrubber to the atmosphere. Other differences in gas compositions are minor and are not expected to invalidate the applicability of scrubber systems for FCCU regenerators.

The similarities in flue gas flow rates and characteristics between industrial boilers and FCCU's (refer to Docket A-79-09, item II-B-21) and consideration of their differences support the reasonable conclusion that industrial boiler sodium scrubber performance is applicable to FCCU's. Source test results for a sodium scrubber applied to an industrial boiler burning a high sulfur fuel show that sodium scrubbers can achieve at least 90 percent reduction in SO_x emissions at high inlet SO_x concentrations (refer to Docket A-79-09, item II-A-11). Therefore, EPA has reached a reasonable conclusion that the

FCCU standard is achievable and that scrubbers are applicable over the expected range of FCCU regenerator exhaust gas sulfur concentrations.

The commenter did not provide any information to show that scrubber performance for industrial boilers would be different than scrubber performance for FCCU's. Therefore, in consideration of the above mentioned similarities, EPA believes that it is reasonable to expect that scrubber performance for industrial boilers is applicable to FCCU's.

Comment:

One commenter (IV-D-16) asked if the licensor of the sodium scrubber system currently applied to FCCU's will guarantee 90 percent SO_x removal as opposed to SO_2 removal.

Response:

Since proposal, the regulated pollutant has been changed to SO_2. As discussed below, 90 percent SO_x reduction has been guaranteed, and thus SO_2 removal would similarly be guaranteed.

Sodium scrubbers applied to FCCU's are venturi-type scrubbers designed to achieve high levels of SO_x emission reduction. Exxon Research and Engineering (ERE) is the licensor of all sodium scrubbers currently applied to FCCU's. The EPA test results for the ERE scrubber system show that the scrubbers have achieved SO_x control efficiencies in excess of 95 percent (see Docket A-79-09, items II-I-42 and II-I-50). The ERE has guaranteed SO_x control efficiencies of 90 percent for the scrubbers it has installed for other refining companies (see Docket A-79-09, items II-D-41 and II-D-95). However, ERE states that at low inlet concentrations (less than 500 vppm), SO_x removal decreases. Due to sampling and process fluctuation, a minimum outlet concentration of 50 vppm is reasonable (see Docket A-79-09, items II-B-10 and II-D-50) and is included in the standard.

The EPA contacted other sodium scrubber vendors for information regarding the applicability and performance of non-venturi type scrubbers (spray tower or tray tower scrubber designs) to FCCU's. These vendors reported that non-venturi type scrubbers installed to control FCCU SO_x emissions at a location downstream from a particulate control device should achieve at least 90 percent reductions in SO_x emissions (see Docket A-79-09, item IV-J-6). Based on these responses, EPA believes that, besides ERE, other sodium scrubber vendors will guarantee 90 percent SO_x removal in FCCU applications.

Comment:

One commenter (IV-K-2) stated that EPA does not have the authority to issue an NSPS because no add-on control device for sulfur oxide emissions has been adequately demonstrated. The commenter made this claim by maintaining that if "a 3-hour averaging period is too short to ensure that exceedances of the proposed standard would not occur due to normal FCCU or control system variability," then tests of this duration would not prove the adequacy of add-on controls for sulfur oxide emissions. In that event, the commenter noted, the Agency has no data proving the adequacy of devices to lower FCCU SO_x emissions, since "all the data in the BID Appendix C are for short periods."

Response:

Since the standards were originally proposed, the Agency changed the regulated pollutant from SO_x to SO_2 for add-on controls. Even if the regulated pollutant for the standard for add-on controls were still SO_x, the Agency disagrees that the lack of long-term SO_x emission reduction data fails to support a conclusion that scrubbers have been adequately demonstrated for SO_x emissions. [Appendix C does contain long-term (12 day) test data for SO_2.] The Agency believes that the ability of well-operated and maintained scrubbers in each of the short-term tests to attain well over 90 percent SO_x emission reduction supports a scrubber's ability to attain at least 90 percent SO_x emission reduction over a 7-day period, because a 7-day averaging period gives refinery operators more time to correct minor problems in scrubber performance and adjust process variables, such as feedstock changes, whereas a 3-hour period does not. Thus, the Agency disagrees with the commenter's conclusion, and believes that add-on controls are adequately demonstrated for SO_x emissions.

Comment:

One commenter (IV-K-12) stated that EPA's reliance on flue gas scrubbers for effective SO_3 reduction is not warranted. The commenter added that the company has test data, available to the Agency upon request, that indicate that SO_3 percent removal from scrubbers on oil-fired steam generators at a western production field is very low, while

SO_2 percent removal is much higher. According to the commenter, scrubbers are known to be less effective for submicron particulates, although they are efficient for SO_2 and particulate removal.

Response:

The Agency appreciates the concerns expressed by the commenter that flue gas scrubbers are not effective for control of SO_3 emissions. The EPA agrees that scrubber systems may not be as effective in controlling SO_3 as in controlling SO_2. However, as shown in Appendix C of the BID, data on SO_3 removal by scrubbers on FCCU regenerators indicate that SO_3 removal efficiency can be substantial (80 to 99 percent). This appears to contradict, as pointed out, the commenter's data from scrubbers on oil-fired steam generators showing "very low" SO_3 removal. The Agency does not believe this apparent contradiction needs to be resolved for this rulemaking, although it is likely due to differences in scrubber design. Although possibly not as low as indicated by the commenter for all regenerators, SO_3 constitutes a small portion of total SO_x from regenerators using add-on controls. Thus, the potential adverse environmental impact, even if scrubber efficiency for SO_3 removal is actually "very low," will be very small. Thus, the Agency believes that the decision to use SO_2 as the regulated pollutant for regenerators with add-on controls is still appropriate.

Comment:

One commenter (IV-D-7) stated that flue gas desulfurization (FGD) systems (i.e., scrubbers) have poor operability. Scrubber shutdowns would result in more frequent FCCU shutdowns, reducing refinery profitability and the nation's refining capacity.

Response:

At proposal, sodium scrubbing systems had been effectively applied to seven FCCU regenerators at five refineries to control SO_x emissions. These seven FCCU regenerators represent 11 percent of nationwide FCCU processing capacity. Since proposal, to the Agency's knowledge, two other scrubbers controlling FCCU's at two refineries have begun operation. There is no information to show that the operation of these sodium scrubbers has increased FCCU shutdowns, reduced refinery capacity, or reduced refinery profitability. The commenter provided no data to support his claims. The sodium scrubbers applied to FCCU's have operated continuously with no failures between FCCU turnarounds (see Docket A-79-09, item II-B-10). Thus, EPA continues to believe scrubbers are an effective control method for reducing FCCU SO_x emissions.

3.2 SO_x REDUCTION CATALYSTS

Comment:

Commenters (IV-D-2, IV-D-7, IV-D-8, IV-D-9, and IV-D-10) stated that SO_x reduction catalysts are not demonstrated and cannot achieve 80 percent reductions in SO_x emissions. Three commenters (IV-D-2, IV-D-9, and IV-D-10) argued that EPA's data on 80 percent reductions in SO_x emissions are based on "ideal" feedstocks which are not representative of many refinery operations. One commenter (IV-D-7) pointed out that SO_x reduction catalysts will reduce a refiner's flexibility in selecting FCCU cracking catalysts thereby affecting FCCU efficiency in processing a variety of feedstocks. Another commenter (IV-D-9) stated that: (1) the thoroughness of contact between the SO_x reduction catalyst and regenerator gases determines the maximum achievable SO_x control; (2) innovations in regenerator technology that reduce regenerator catalyst inventory will reduce contact time and thereby negatively affect SO_x reduction catalyst capability; (3) FCCU regeneration efficiency deteriorates over the course of a 2- to 3-year period, and this deterioration, which may affect the performance of SO_x reduction catalysts, is not addressed by any existing commercial test data; and (4) the impact of feedstock sulfur content and composition on SO_x reduction catalyst effectiveness has not been fully recognized, and could impede applicability of the catalysts at moderate feedstock sulfur levels.

Response:

The EPA considers SO_x reduction catalysts to be an emerging technology. The standards allow for their use and thereby encourage their further development. Current catalysts show promising results. According to SO_x reduction catalyst developers, current SO_x reduction catalysts can achieve SO_x emission reductions of 65 to 75 percent (see Section 2.5.2). Concerns and uncertainties about catalyst performance remain because the technology is not fully developed at this time. Developers of SO_x reduction catalysts report that optimum performance of SO_x reduction catalysts is achieved when: (1) the FCCU is operated in the complete CO combustion mode with an excess oxygen content of 1.5 to 2.0 percent by volume in the FCCU regenerator exhaust gas; (2) FCCU regeneration temperatures are maintained as low as possible while maintaining complete CO combustion; and (3) good contact is maintained between the SO_x reduction catalyst and combustion air within the regenerator (see Docket A-79-09, item IV-B-9). Thus, it is possible that operating restrictions may prevent some refiners from achieving the standard for FCCU's without add-on controls using SO_x reduction catalysts only. In these cases, the refiner can achieve the standards by using hydrotreated or low sulfur feedstocks, either alone or in combination with SO_x reduction catalysts, or by scrubbing.

Comment:

One commenter (IV-D-1) stated that recently completed studies show that SO_x reduction catalysts are capable of achieving the necessary SO_x reductions such that FCCU's operating at refineries located in Southern California can achieve Phase II of Rule 1105 of the SCAQMD regulations (60 kg SO_2/1,000 barrels of feed).

Response:

Phase II of Rule 1105 is more stringent than the standard for FCCU's without add-on controls proposed by EPA. The commenter's indication that SO_x reduction catalysts used in FCCU's located in Southern California are expected to achieve an emission limit more stringent than this standard supports EPA's determination that, in many cases, the SO_x reduction catalysts can achieve the level of the 9.8 kg SO_x/1,000 kg coke burn-off.

3.3 LOW-SULFUR FEEDSTOCKS

Comment:

One commenter (IV-D-16) stated that the proposal BID did not consider using virgin feedstocks that naturally contain low sulfur as a control technique for FCCU SO_x emissions. The commenter recommended that the standards be reevaluated with consideration given to whether the proposed standards will have any impact because of the probable diversion of low-sulfur feedstocks to affected facilities. The commenter suggested that EPA calculate an "avoidance cost" for refiners using low sulfur FCCU feedstocks.

Response:

The proposal BID did not evaluate the exclusive processing of low sulfur virgin feedstocks as a control alternative for reducing FCCU SO_x emissions. At the time the proposed standards were being developed, refiners in the United States were experiencing limited supplies and high prices for low sulfur feedstocks and crude oils. As a consequence, new process units were installed at many refineries in order to allow the processing of high sulfur crude oils. Thus, EPA did not believe that low sulfur feedstocks would be a cost-effective alternative to achieve these standards. The proposed standards, however, provided a feed sulfur cutoff. The EPA recognizes that low sulfur virgin feedstocks are one means a refiner may choose to achieve compliance with either the standard for FCCU's without add-on controls or feed sulfur cutoff. At present, the availability of low sulfur crude oils has improved and crude oil prices have significantly declined from the peak 1980 prices, but not all refiners will choose to limit FCCU processing to low sulfur virgin feedstocks. Many refiners are currently processing crude oils containing 1 to 2 percent sulfur. Furthermore, the potential exists that refiners will be processing higher sulfur content crude oils within the next 5 years. Therefore, EPA expects that most refiners will use SO_x reduction catalysts, hydrotreating, or scrubbers to achieve these standards.

4.0 ENVIRONMENTAL AND ENERGY IMPACTS COMMENTS

4.1 MODEL PLANTS USED FOR IMPACT ANALYSES

Comment:

One commenter (IV-D-16) stated that the FCCU fresh feed capacity is less today than January 1980, and that the numbers and sizes of FCCU's used by EPA for analyzing environmental, energy, and economic impacts are incorrect. The commenter stated that the impacts should be reevaluated using the reduced estimates of the size and number of new and revamped FCCU's. The commenter cited data from the Oil and Gas Journal showing decreasing capacity to support his claims.

Response:

According to the Oil and Gas Journal (see Docket A-79-09, item IV-J-2), total FCCU capacity has decreased from 1980 to 1984 by 21,450 m^3/sd, or about 2.5 percent. This decrease is a result of the shutdown of FCCU's at unprofitable refineries which have closed since 1980. However, also during this period, a number of existing FCCU's were modified or reconstructed, and new FCCU's were constructed.

New FCCU construction and modification and reconstruction of existing units are reported in Hydrocarbon Processing "Boxscores" (see Docket A-79-09, item IV-J-3). A review of this information shows that 12 new FCCU's were undergoing construction and 14 existing units were undergoing expansion or revamping between the years 1981 and mid-1984. Based on this information, EPA still believes that the growth estimates provided in the proposal BID are reasonable. The EPA projected that 10 new and 7 modified or reconstructed FCCU's would be subject to these standards within 5 years. The size of the new, modified, and reconstructed FCCU's projected by EPA in the proposal BID also appear reasonable based on these data (see Table A-10 for estimated sizes).

Comment:

One commenter (IV-D-16) stated that the 3.5 weight percent sulfur feed level model plant should not be included in the impact analyses because the 3.5 percent sulfur model does not reflect industry practice. The commenter cited a "Davison Catalagram 66" (1982) which stated that only one heavy oil FCCU processed feed with a sulfur content above

2 percent and that the median value of the feedstock sulfur content was 0.6 percent.

Response:

The EPA developed model plants based on current industry practices and on projected refining trends over a 5-year period. At the time the model plants were developed, many refining companies were developing and putting in place "bottom-of-the-barrel" refining to allow the processing of higher sulfur feedstocks than currently practiced by the industry. Model plants were selected to span the range of possible feedstock sulfur contents including "bottom-of-the-barrel" refining. The EPA recognizes that most refiners currently are processing feedstocks containing up to about 2 weight percent sulfur, but the potential exists that FCCU's (especially HOC's) will be processing higher sulfur feedstocks within 5 years. Thus, although the 3.5 weight percent sulfur model plant may not reflect current industry practice, a reasonable potential exists that some FCCU's will be processing during the next 5 years feedstocks containing greater than 2 weight percent sulfur. Therefore, it is reasonable to include the 3.5 weight percent sulfur model plant in the impact analyses.

Comment:

One commenter (IV-D-16) asked why environmental, energy, and economic impacts for calcium-based scrubbers were omitted from the proposal BID.

Response:

The analysis of various scrubbing systems presented in Chapter 4 of the proposal BID was not meant to be all inclusive. The environmental, energy, and economic impacts for calcium-based scrubbers applied to FCCU's were not analyzed in the proposal BID because if a refiner does not use a sodium scrubber to achieve the standards, EPA expects that the refiner would choose either a dual alkali or a regenerable scrubber system. However, a refiner could choose to use a calcium-based scrubber to achieve these standards.

4.2 WATER IMPACTS

Comment:

Five commenters (IV-D-4, IV-D-5, IV-D-7, IV-D-16, and IV-D-20) stated that the waste disposal aspects of the proposed standards are more complex than shown by the analysis presented in the proposal BID. One commenter (IV-D-16) stated that no inland refiner would be able to obtain a permit for the discharge of waste liquids from sodium scrubbers. This commenter noted that sodium scrubbers have been used only where oceans or large rivers could be used for disposal. The commenter requested that EPA show that inland refineries could receive discharge permits under Federal regulations. Another commenter (IV-D-5) stated that refineries not located near large bodies of water would need to install expensive additional wastewater treatment systems to meet permitted discharge levels. This commenter cited the costs for replacement of a fly ash pond for a Wellman-Lord scrubber used at a power plant, and stated that settling ponds can be expected to receive scrutiny under the Resource Conservation and Recovery Act (RCRA).

Response:

The EPA agrees that the waste disposal aspects associated with application of scrubbers are complex. However, it is EPA's judgement that sodium scrubbers or other types of scrubber systems can be installed and operated at reasonable costs for refineries at inland locations.

The petroleum refining effluent guidelines (40 CFR 419) technically apply to all wastewater from air pollution control devices when these wastes are treated with the main refinery wastewater or are discharged from the main refinery wastewater treatment system. The costs for the treatment of these wastes are accounted for under the Part 419 regulations. If the scrubber wastes are processed, treated, or discharged separately from the main refinery wastewater collection, treatment, or disposal system, then case-by-case determinations would be made to regulate them. However, the major polluting characteristic of the treated sodium scrubber wastestream is its high dissolved solids content, about 6 percent solids by weight, which consists primarily of sodium sulfates. There are currently no Federal regulations applicable to the dissolved solids content of the sodium scrubber wastestream. Instead, limitations on dissolved solids, where appropriate, would be developed on a case-by-case basis, outside of the Federal effluent guidelines. Such limitations would be based on whether the receiving water body can accommodate a discharge and still comply with a State's water quality standards. The EPA's Quality Criteria for Water specifies a maximum dissolved solids content of 500 mg/l in fresh water. Sodium scrubber wastes are produced at the rate of 0.19 to 0.38 m^3 per minute. Unless the receiving water body has sufficient flow for dilution, its dissolved solids content will exceed the water quality criterion downstream from the sodium scrubber discharge point.

For many refineries, the sodium scrubber wastewater would constitute a small portion of the total refinery wastewater flow. Therefore, the dissolved solids content of the combined scrubber and treated refinery wastestreams may be within acceptable levels. A permit may be issued for the discharge of sodium scrubber wastes to a publicly-owned treatment works (POTW) by way of a sewer if the POTW receives sufficient total wastewater flow from the municipality it serves such that the scrubber wastestream dissolved solids are diluted to acceptable levels.

At proposal, there were seven sodium scrubbers operating to control SO_x and particulate emissions from FCCU's. All seven sodium scrubbers are located at coastal locations. Since proposal, to the Agency's knowledge, two other scrubbers controlling SO_x and particulate emissions from FCCU's have begun operation. At least one of these discharges to salt or brackish water. No requirements exist for the discharge of sodium scrubber wastes to brackish or salt water. Disposal to brackish or salt water or discharge to a sewer will not be available to all refiners in inland locations. This was acknowledged by EPA in the proposal preamble. Where permits are unavailable for direct discharge to surface waters or sewers, other wastewater disposal methods may apply. These other disposal methods include evaporative ponding, deep-well injection, and recycle. Evaporative ponding is limited to those western States where evaporation exceeds precipitation. Deep-well injection is of limited applicability due to the hazards of groundwater contamination in many parts of the United States. If a refiner elects to install a sodium scrubber but cannot obtain a discharge permit, he will need to use one of these disposal methods. The added cost of these disposal methods would be greater than the disposal cost used for EPA's cost estimates. However, other scrubber systems, such as dual alkali, are available to meet the standard for add-on controls at reasonable cost.

Sodium scrubbers have been used extensively at inland locations to control SO_x emissions from industrial boilers. From a total population of 47 sodium scrubbers currently applied to industrial boilers, 5 discharge to a sewer, 9 discharge to surface water, 23 use ponding, 7 use deep-well injection, and 1 uses recycle to dispose of the wastestream. Therefore, it is possible for a refiner at an inland refinery location either to obtain a permit to discharge sodium scrubber wastes to surface water or sewers, or to use another means to dispose of the liquid wastes.

As mentioned above, other SO_x scrubber systems with minimal wastewater impacts are applicable to FCCU's at a reasonable cost. These include dual alkali and spray drying scrubbing, which have no significant liquid wastes but instead produce solid wastes; or Wellman-Lord and citrate scrubbing, which have no significant liquid wastes and produce a salable sulfur product. These scrubbing systems have demonstrated removal efficiencies of 90 percent on industrial boilers (see proposal BID, Chapter 4). Due to the similarities between industrial boiler and FCCU flue gases (discussed in Section 3.2), these scrubbing systems are applicable to FCCU's. The costs and cost effectiveness of these scrubbers were evaluated by EPA in the proposal preamble (see proposal BID, Chapter 8), and again for dual alkali scrubbers in response to these comments (see Docket A-79-09, item IV-B-15) and are judged to be reasonable. Table A-8 in the Appendix to this volume provides dual alkali scrubbing costs developed since proposal. Alternatively, the refiner may choose to demonstrate compliance with the standard for FCCU's without add-on controls by using hydrotreating or SO_x reduction catalysts, or by complying with the feed sulfur cutoff using low sulfur feedstocks.

The sodium scrubber wastewater contains catalyst fines removed from the FCCU regenerator exhaust gas. These catalyst fines are removed from the wastestream in a settling pond. Eventually, these catalyst fines would be removed from the settling pond and disposed of in a landfill. Currently, catalyst fines are collected in electrostatic precipitators (ESP's) to meet the FCCU particulate NSPS, and are disposed of in landfills. Catalyst fines, when removed from the settling pond, will be wet and will include dissolved sodium salts such as sodium sulfate, sulfite, and bisulfite. However, neither catalyst fines nor sodium salts are reactive in water and do not create a leachate problem like coal fly ash. Therefore, the SO_x NSPS will not affect the method selected for disposal of catalyst fines. Thus, it is doubtful that a catalyst fines settling pond would fall under RCRA.

Comment:

One commenter (IV-D-20) agreed with EPA that single alkali scrubbers may not be applicable in inland refinery locations or areas where water availability or wastewater discharge is restricted. In support of this, the commenter provided an example calculation showing the impact of sodium scrubber blow-down on refinery wastewater quality, and stated that such a high level of total dissolved solids in the blowdown would seriously reduce the efficiency of the activated sludge plant, leading to high dissolved solids in the receiving waters. The commenter stated that the high dissolved solids impacts on receiving waters would necessitate the installation of dual alkali scrubbers.

Response:

As discussed above, EPA agrees that the potential impact that high dissolved solids from sodium scrubbers would have on receiving waters may, in certain cases, necessitate use of another control technique, such as a dual alkali scrubber. However, it is EPA's opinion that the sodium scrubber will not negatively affect a refinery's wastewater treatment plant.

The EPA's analysis of sodium scrubbers presented in the proposal BID includes the cost of wastewater treatment facilities. These facilities include a settling pond for removal of catalyst fines and an aeration basin to reduce the chemical oxygen demand of the wastestream. By using these wastewater treatment facilities, the scrubber wastestream does not need to pass through the refinery's main wastewater treatment plant. If the treated effluent from the sodium scrubber wastewater treatment facility is mixed with the treated effluent from the refinery's main wastewater treatment plant, the refinery's main wastewater treatment plant will not be affected.

4.3 SOLID WASTE IMPACTS

Comment:

One commenter (IV-D-16) questioned two statements presented in the preamble to the proposed standards that pertained to solid waste impacts. The commenter asked why sodium scrubbers would have no added cost impacts for solid waste disposal and why the preamble states that sodium scrubber waste is 50 percent water by weight. Since the waste is 50 percent water, the commenter reasoned that the waste disposal costs should be twice as much. Another commenter (IV-D-7) wrote that the proposed standards do not adequately address the solid waste impacts of scrubber systems. According to the commenter, scrubber systems could greatly increase the amount of solid waste generated by a refinery and disposal costs would rise accordingly, if disposal locations are available.

Response:

The sodium scrubbing systems that are currently applied to FCCU's control both particulate emissions as well as SO_x emissions. With this type of scrubber, an additional particulate control device would not be required to achieve the current particulate standard. Control of FCCU particulate emissions (primarily catalyst fines) by a sodium scrubber does not incrementally increase the dry weight of solid waste over control by a dry particulate control device, such as an ESP. Therefore, the amount of particulates collected by the sodium scrubbers are not "chargeable" to the SO_x standards. However, solids collected in a scrubber would be wet and, thus, weigh more and encompass a larger volume. It will cost more to transport and dispose solids collected in a scrubber to a landfill than dry solids. The increase due to the amount of water added to the solids is "chargeable" to the SO_x standards and is included as a "solid waste" cost in the analysis of sodium scrubber costs. In addition, a "liquid waste" disposal cost was added as a conservative estimate of the costs to dispose treated liquid scrubber waste to the sewer (see Section 5.1 of this document).

In order to determine the additional solid waste disposal cost due to the water contained in settled scrubber solids (sludge), it was necessary to determine the percent solids content of the scrubber solids. However, to date, none of the settling ponds used for sodium scrubbers applied to FCCU's has been emptied. Thus, EPA has no information regarding the water content of settled particulates (sludge) collected by a sodium scrubber. Instead, EPA has information regarding the solids content of wastes for other scrubbing systems, such as dual alkali scrubbers. For these other systems, scrubber waste is typically 60 percent solids. To be conservative, EPA assumed that the settled sodium scrubber waste would be approximately 50 percent solids, by weight. The EPA believes that sodium scrubbers would not significantly increase the amount of solid waste generated by a refinery.

Other types of nonregenerable scrubber systems, such as dual alkali, spray drying, or lime/limestone scrubbers, produce a greater quantity of solid waste with little liquid discharge compared to sodium scrubbers. A dual alkali scrubber controlling SO_x emissions from an FCCU processing a 1.5 weight percent sulfur feedstock will produce approximately 7,700 Mg/yr of solid waste for a 2,500 m^3/stream day (sd) FCCU and 25,000 Mg/yr for an 8,000 m^3/sd FCCU. The EPA considers the solid waste impacts for these systems reasonable. Should solid waste disposal not be possible, the refiner would need to consider control techniques that do not produce solid waste. These include using regenerable scrubber systems (e.g., Wellman-Lord or citrate scrubbers which produce salable sulfur products), hydrotreating, SO_x reduction catalysts, or the purchase of low sulfur feedstocks.

Comment:

One commenter (IV-D-4) stated that the proposed standards discourage the recovery of reusable material by imposing sodium scrubbers which consume large quantities of raw materials and produce other less desirable wastes. Each megagram of SO_2 scrubbed will consume 1 Mg of sodium hydroxide. The waste is a potential surface and groundwater contaminant.

Response:

The EPA disagrees that the proposed standards discourage the recovery of sulfur. The standard for FCCU's without add-on controls allows the use of hydrotreating or SO_x reduction catalysts. With both of these control technologies, sulfur removed from the FCCU feedstock or from the regenerator is eventually reclaimed as a salable product in the refinery sulfur plant.

The amount of sodium hydroxide consumed by sodium scrubbers is approximately 1.15 times the amount of SO_x in the gas stream passing through the scrubber. The EPA evaluated the impacts of secondary pollutants resulting from the application of scrubbers and determined that these impacts are reasonable. The water impacts of scrubber wastewater discharge are discussed in Section 4.2 of this document, and the cost impacts are discussed in Section 5.1 of this document.

Comment:

One commenter (IV-D-16) stated that according to the preamble, SO_x reduction catalysts are not expected to have a solid waste impact. By dividing the nationwide fifth-year cost for SO_x reduction catalysts ($20 million/yr) by the reported cost of the catalysts ($1,800/Mg), the commenter determined that the use of SO_x reduction catalysts would increase FCCU solid waste by 11,000 Mg/yr.

Response:

The EPA does not believe that the use of SO_x reduction catalysts would result in a significant increase in FCCU solid waste for the reasons discussed below. When used as an additive, SO_x reduction catalysts replace from less than 5 and up to 10 percent of the circulating catalyst inventory (see Docket A-79-09, items II-D-57 and IV-D-24). One of the catalyst developers stated that, due to the softness of their SO_x reduction catalyst (an additive), its makeup rate is greater than that for the cracking catalyst. The developer reported that this may result in an increase in solid waste of up to 40 percent. Based on recent tests by another developer, solid waste increases of less than 5 percent are anticipated for the newer SO_x reduction catalyst formulations because these are much harder than earlier formulations. The EPA believes that it would be in the catalyst developers interest to produce a harder reduction catalyst because a harder formulation would have a lower makeup rate and therefore, most likely cost less to use than a softer one. Other recently developed catalyst formulations incorporate the SO_x reduction catalyst as a constituent of the cracking catalyst and consequently, SO_x control can be accomplished without increasing the total quantity of cracking catalyst used in the FCCU over a period of time. In this case, SO_x reduction catalysts would not increase particulate emissions or solid waste. In summary, whether the SO_x reduction catalyst is in the form of an additive or a constituent of the cracking catalyst, it is unlikely that the use of newer SO_x reduction catalyst formulations would significantly increase FCCU solid waste over current levels.

4.4 ENERGY IMPACTS

Comment:

One commenter (IV-D-5) stated that the scrubber electric requirements presented in the proposal BID are too low. Instead of the 0.2 to 2 percent increase in electric consumption estimated by EPA, the commenter stated that an increase in FCCU energy consumption of 100 percent would be more realistic. The commenter operates a Wellman-Lord scrubbing system to control SO_x emissions from a utility boiler. The commenter stated that energy usage for the scrubber is 10 MW compared to the 0.166 MW energy usage estimated by EPA for an 8,000 m^3/sd model plant. The higher energy usage is due to the use of booster blowers necessary to pressurize the flue gas in order to move the gases through the Wellman-Lord scrubber, especially following a CO boiler.

Response:

The EPA reevaluated its estimate of the electrical energy requirements of Wellman-Lord scrubber systems. The gas stream leaves the FCCU regenerator at a higher pressure than the flue gas exiting a boiler. As a result, less energy is required to move the FCCU regenerator exhaust gas through a Wellman-Lord system or other scrubber system than the energy used for a boiler application. Therefore, scrubber energy requirements should be lower for an FCCU application than for an industrial or utility boiler application. The Wellman-Lord system energy requirements presented in the proposal BID are based on an FCCU operating with high temperature regeneration instead of a CO boiler. The EPA expects the majority of new, modified, and reconstructed FCCU's to operate with high temperature regeneration. Consequently, EPA believes that the estimate of the electrical energy requirements of Wellman-Lord scrubber system presented in the proposal BID is reasonable.

The energy impacts reported in the proposal BID are based on the energy requirements of sodium scrubbers rather than Wellman-Lord systems because sodium scrubbers are the only scrubber systems that have been applied to FCCU's and they are the systems EPA expects most refiners to install to achieve the standard for add-on controls. The commenter provided no information regarding sodium scrubber energy requirements. Therefore, EPA did not revise the energy impact of sodium scrubbers. The EPA does acknowledge that an FCCU owner or operator choosing to use a Wellman-Lord system may experience greater energy impacts than if one chooses to use a sodium scrubber.

4.5 AIR IMPACTS

Comment:

Four commenters (IV-D-3, IV-D-6, IV-D-8, and IV-D-16) questioned the appropriateness of using scrubbers if they increase ground-level SO_x concentrations. One commenter (IV-D-3) wrote that controlling FCCU SO_x emissions to a level below a 13 kg SO_x/1,000 kg coke burn-off level would only bring about a small decrease in a ground-level impact, an impact that is already quite small. If control to a level below 13 kg SO_x/1,000 kg coke burn-off is accomplished by scrubbing, the cooling of the exhaust gas would lower the plume rise, thereby diminishing the small air quality benefit, or in some cases, cause a net increase in ground-level concentration. A 13 kg SO_x/1,000 kg coke burn-off level would reduce the air quality benefits of the proposed NSPS little, if at all.

Another commenter (IV-D-16) suggested that EPA require reheating the scrubber exit gases to reduce ground-level concentrations and to include reheat in the sodium scrubber cost analysis. This commenter stated that the flue gas temperature used in the modeling is below the sulfuric acid dew point (200°C). The commenter suggested a stack temperature of 260°C and a flue gas exit velocity of 15.3 m/s. The commenter further suggested that stack heights and exit velocities reported for the modeling of Regulatory Alternative I are distorted.

Response:

Scrubbing a gas stream lowers the temperature of the gas stream. Unless the gas stream is reheated downstream of the scrubber, the plume emitted from the scrubber stack will be cooler than the plume emitted from a FCCU regenerator not using a scrubber. Lowering the temperature of the plume reduces the effective height above the ground to which the plume will rise.

The results of dispersion modeling performed by EPA and presented in the proposal BID were used to analyze the air quality impact of the proposed standards. In all cases, ground level SO_x concentrations are within the national ambient air quality standards. For all the model plant scenarios except the one processing a low sulfur feedstock, the ground level SO_x concentrations predicted for implementation of the proposed standards are lower than the baseline (uncontrolled) concentrations. In these cases, the decrease in SO_x emissions afforded by implementation of scrubbers offsets the lower plume rise. This analysis showed that applying a scrubber to a model plant processing a low sulfur feedstock (0.3 weight percent sulfur) to achieve 9.8 and 6.5 kg SO_x/1,000 kg coke burn-off levels (Regulatory Alternatives III and IV, respectively) would increase the 1-hour maximum ground level SO_x concentration downwind of the FCCU to a level above the baseline (uncontrolled) case. The small amount of emission reduction achieved by the control alternatives did not compensate for the lower plume rise resulting from the cooler exhaust gas temperature. However, this model plant scenario would not occur in actuality because any FCCU processing 0.3 weight percent sulfur content feedstocks would comply with the low-sulfur cutoff and, therefore, a scrubber would not be installed on the source. Also the model assumes that a scrubber would reduce model plant SO_x emissions to the level of the regulatory alternative. The SO_x emission reductions required to achieve the model plant regulatory alternatives considered are less than the 90 percent required by the standard.

The EPA agrees that if a control technique other than a scrubber was used to achieve the same emission reduction as the scrubber would achieve, the resulting maximum ground level concentrations may be less than if a scrubber were used. However, the application of SO_x reduction catalysts to meet the standard for FCCU's without add-on controls would provide less emission reduction than the application of scrubbers. The additional emission reduction provided by scrubbers would likely compensate for the lower plume rise, so that the use of scrubbers would result in lower ground level concentrations than the use of SO_x reduction catalysts.

The stack temperatures, heights, and exit velocities used in the modeling analysis were selected as average values from data for actual

FCCU scrubbers. Only one of the seven FCCU sodium scrubber installations existing before proposal is equipped with scrubber stack reheat. Reheat is used only occasionally to reduce the visible steam plume during certain weather conditions. The stack parameters EPA selected for the model plants are based on actual sodium scrubber installations. For this reason, EPA believes that the modeling input parameters selected and the assumption of no reheat are appropriate.

Comment:

One commenter (IV-D-9) stated that the use of the correlation between feed sulfur and coke sulfur overstates uncontrolled SO_x emissions, inflating the percent reduction attributed to catalysts.

Response:

The EPA agrees that the correlation, presented on p. 3-18 of the proposal BID, overstates SO_x emissions for some feedstocks. However, at the same time, it understates SO_x emissions from other feedstocks. The correlation used by EPA was provided by industry and is based on test data for a large number of FCCU's and feedstock types. For this reason, EPA concludes that the correlation shown in the proposal BID is representative of uncontrolled emissions. The EPA considers the correlation a useful and reasonable means for estimating uncontrolled FCCU SO_x emissions and SO_x reduction catalyst performance.

Comment:

One commenter (IV-D-16) stated that the preamble does not adequately address the effect of SO_x reduction catalysts on NO_x emissions. The commenter argued that the preamble states that SO_x reduction catalysts would not increase NO_x emissions. However, the proposal BID (Sections C.3.1.1 and C.3.1.2) and Docket A-79-09, item II-B-20 show that SO_x reduction catalysts raised NO_x emissions.

Response:

Most refiners use one of two techniques to control CO emissions from the FCCU regenerators: HTR or catalytically promoted CO combustion. Data from some tests of NO_x emissions from regenerators using both CO combustion promoter catalysts and SO_x reduction catalysts in combination show an increase in NO_x emissions. Separate data for regenerators using CO combustion promoters without SO_x reduction catalysts suggest that the use of these catalysts may increase NO_x emissions. Thus, at this time, it is unclear whether the NO_x increases observed for SO_x reduction catalyst tests are due to the reduction catalyst or the CO combustion promoter. Recent commercial tests of SO_x reduction catalysts in FCCU's utilizing HTR show no increase in NO_x emissions (see Docket A-79-09, item IV-B-9). No recent tests of SO_x reduction catalysts in FCCU's utilizing CO promoters were available. Because most FCCU's subject to the standards are expected to use HTR and because newer SO_x reduction catalyst formulations have not increased NO_x emissions, EPA believes that the use of the SO_x reduction catalyst technology will not increase NO_x emissions.

Comment:

One commenter (IV-D-16) stated that the proposal BID fails to take State regulations into account in estimating baseline emissions for Regulatory Alternative I. To remedy this, the commenter recommended that the selection of model plants include site selection for each unit. Then, baseline emissions can be estimated based on the State in which the model unit is located.

Response:

Emissions of SO_x from FCCU's can vary significantly depending on the feedstock processed, FCCU operation, and capacity utilization. Many refiners have been able to achieve existing State SO_x regulations with little or no control. It is difficult to determine FCCU SO_x emission rates taking individual State regulations into account because the various formats of State regulations do not lend themselves to simplifying assumptions regarding FCCU SO_x emissions.

Selection of sites for each model plant is not a reasonable approach as there is no basis for site selection. Using an emission factor provides a reasonable estimate of baseline nationwide FCCU SO_x emissions. This factor is based on emission test results for typical FCCU operations that represent the level of SO_x control achieved by FCCU's to achieve State and local SO_x regulations prior to 1979. State and local SO_x regulations have changed little since 1979; those regulations that have changed do not affect EPA's estimate of nationwide baseline FCCU SO_x emissions.

Comment:

One commenter (IV-D-16) asked why Table 1-1 in the proposal BID shows a "-4" air impact in three cases.

Response:

A "-4", denoting significant short-term air impact, was entered in Table 1-1 because FCCU's represent a significant source of SO_x emissions. This means that FCCU's emit much greater than 100 tons per year of SO_x. Because FCCU's are a significant source of SO_x, and an SO_x control technology with reasonable cost and nonair environmental impacts was identified for FCCU's, a short-term large adverse air impact would result if: (1) standards more stringent than the current level of SO_x control were not developed, (2) development of standards was delayed, and (3) no standards were developed.

Comment:

One commenter (IV-D-16) stated that an emission factor is used to determine current nationwide FCCU SO_x emissions. If the factor is correct, EPA should use this factor to estimate model plant emissions.

Response:

The emission factor used by EPA to determine nationwide FCCU SO_x emissions is based on actual emission test data and does not predict what potential SO_x emissions will be from new, modified, and reconstructed FCCU's. Model plants were developed based on feed sulfur levels and throughputs; model plant emissions are based on the use of the feed sulfur-SO_x emissions correlation presented in the proposal BID. Model plants generated in this way do not necessarily reflect current FCCU operations or emissions but instead represent those newer FCCU's that will be subject to these SO_x standards over the next 5 years. Thus, model plants provide a more reasonable estimate of emissions from the FCCU's that will be subject to this standard than an emission factor based on a composite of older FCCU's.

Comment:

One commenter (IV-K-2) questioned the source of EPA's claim that uncontrolled emissions from a typical FCCU are between 2,000 and 6,000 Mg/yr and that controlled emissions from a typical FCCU are between 400 and 1,200 Mg/yr.

Response:

The uncontrolled emissions estimates referred to in the comment represent Regulatory Alternative I (Baseline) for model FCCU units with a throughput capacity of 2,500 and 8,000 m^3/day, respectively, with a fresh feed sulfur content of 1.5 percent. The Agency estimates that this feed sulfur content would be typical of FCCU's subject to the standard. Emissions were calculated on the basis of 1,400 vppm for feed sulfur content of 1.5 weight percent. This vppm estimate is consistent with actual data from pilot and commercial FCCU's, shown in Figure 3-6 of the proposal BID. The controlled emission estimates of 400 Mg/yr and 1,200 Mg/yr represent control in the 2,500 m^3/day and 8,000 m^3/day regenerator, respectively, to 9.8 kg SO_x/1000 kg coke burn-off. This level can be met by SO_x reduction catalysts being used at facilities with a fresh feed sulfur content of 1.5 percent. If scrubbers are used, lower controlled emissions would occur at this typical FCCU.

5.0 COSTS AND ECONOMIC IMPACTS COMMENTS

5.1 SCRUBBER COSTS

Comment:

Five commenters (IV-D-5, IV-D-6, IV-D-9, IV-D-10, and IV-D-20) stated the opinion that the scrubber costs presented in the proposal BID are unrealistic and are significantly underestimated. The commenters claimed that the scrubber cost estimates should be 2.2 to 7 times higher. The reasons cited by the commenters for the low cost estimates are:

(1) The EPA based the cost analysis on erroneous assumptions for FCCU exhaust volumes, scrubber waste disposal costs, and offsite costs.

(2) The EPA did not consider site space availability and soil conditions, FCCU turnaround schedule, equipment availability, startup costs, or climate when preparing the capital costs estimates. These factors can cause considerable variation in cost of FCCU's at different refineries.

(3) The EPA did not cost dual alkali FGD systems at any of the model units, although use of dual alkali systems might be required in areas where water availability or wastewater discharge is restricted.

(4) The EPA should include separate costs to account for the difficulty of retrofit installations.

(5) The EPA did not consider a cost for business interruption that would result from a scrubber malfunction shutting down the FCCU.

(6) It is not appropriate for EPA to subtract a credit for ESP costs from the scrubber costs in the case of an existing FCCU with an ESP if scrubbers are required as a result of modification or reconstruction.

Response:

To respond to these comments, EPA decided first to solicit more detailed cost data for single alkali scrubbers from vendors and then to perform a general reevaluation of the cost data presented in the proposal BID. Concurrently, EPA solicited supplemental cost data from commenters and then addressed the individual comments pertaining to specific cost items.

A. General Cost Review. First, EPA solicited data from scrubber vendors other than Exxon; Exxon provided the costs on which the proposal BID cost estimates were based. The EPA received detailed cost data from two other scrubber vendors, Environmental Elements Corporation (EEC) and Andersen 2000 (IV-D-32, IV-D-36). Exxon is the only company whose scrubber has actually been installed on an FCCU. Environmental Elements Corporation has, however, served as a subcontractor to Exxon in installation of several Exxon scrubbers, and, therefore, is familiar with FCCU operation, refinery codes, and equipment specifications. Andersen 2000 has considerable experience with the design and application of scrubbers to industrial boilers, but not to FCCU's.

The analysis of these data (see Docket A-79-09, item IV-B-14) showed that the costs provided by Exxon, the vendor of single alkali scrubbers applied to FCCU's, were the highest of all the vendor cost estimates and are conservative due to more stringent design specifications than other vendors use and the use of redundant equipment that serve to provide the scrubber with the reliability that petroleum companies believe is necessary in the refining industry. In particular, the Exxon system design specifications call for vessel design coded by the American Society of Mechanical Engineers (ASME) and design of pumps, piping, and electrical equipment coded by the American Petroleum Institute (API); one of the other two vendors that provided cost data did not specify such coded design. Exxon scrubber vessels are larger than those designed by the other two companies, and use special refractory linings to protect the steel shell from the abrasive effects of catalyst fines in the refinery flue gas. Further, the Exxon design requires sparing of all rotating equipment and critical analyzers, and specifies multiple venturis, rather than a single variable throat venturi as specified by the other vendors. Fluid catalytic cracking units may be in continuous operation for about 3 years nonstop, or significantly longer in some cases, and Exxon designs their scrubbers to maintain safe and reliable operation for time periods equal to that of the FCCU's the scrubbers control.

B. Review of Specific Cost Comments. Second, EPA considered the specific cost comments provided by companies.

One commenter (IV-D-5) stated that EPA's costs were low, in part, because of erroneous assumptions of FCCU exhaust gas volumes. Additional information was requested and received from the commenter, and EPA reviewed the information (see Docket A-79-09, item IV-B-4). The EPA concluded that the exhaust gas volumes used for the cost analysis for FCCU's using HTR appear to be appropriate. Model plant FCCU exhaust gas volumes were developed based on stoichiometric relationships between the coke composition, the amount of air necessary to burn the coke, and typical levels of excess air. The calculated exhaust gas volumes were compared to actual exhaust volumes reported for FCCU regenerators and were found to be reasonable. Furthermore, the values used for the model plant regenerator exhaust gas volumes were sent to industry representatives for review prior to beginning the impact analyses, and no comments were received by EPA indicating that the exhaust gas volumes were not representative of actual conditions.

During these cost evaluations, EPA revised the exhaust gas volume for FCCU's operating with jet ejector venturis (JEV's) to include the flue gas contribution from the CO boiler. As a result, EPA also revised the capital and annual costs for JEV scrubbers installed on FCCU's (see Docket A-79-09, item IV-B-16). Fluid catalytic cracking units using CO boilers must install the JEV-type scrubber. The JEV costs presented in the proposal BID did not account for the additional flue gas volume that would enter a JEV scrubber because of the combustion air required in the CO boiler. The EPA determined that flue gas volume to a JEV scrubber would be about 10 percent higher than the volume of gas from an FCCU to a high-energy venturi scrubber (see Docket A-79-09, item IV-B-16). This increased volume resulted in about a 3 percent increase in the cost of the JEV scrubber over that previously calculated. Tables A-5 through A-7 in the Appendix to this volume contain the revised JEV costs.

Several commenters (IV-D-5, IV-D-6, IV-D-9, IV-D-10) stated that EPA used erroneous assumptions for scrubber waste disposal costs. The EPA, therefore, reviewed the waste disposal costs used in the proposal BID. The cost values used in the proposal BID represent the cost for the transport and disposal of collected catalyst fines in a landfill. This solid waste disposal cost is based only on the additional mass of solid wastes to be disposed due to the use of a wet scrubber as the collection device instead of an ESP (see Section 4.3 of this document). In the proposal BID, no costs were credited to the disposal of the treated liquid wastes because EPA assumed that the treated liquid wastes were disposed to surface water. Upon review, EPA decided that it is appropriate to provide a more conservative estimate of liquid waste disposal costs by assuming that all affected facilities would discharge to sewers. Some refiners, especially in coastal locations, will likely be able to discharge the treated scrubber liquid wastes to surface waters without incurring a sewer discharge cost.

Two commenters (IV-D-5 and IV-D-9) questioned EPA's assumptions of offsite costs. Two other commenters (IV-D-6 and IV-D-10) stated that EPA did not consider site space or equipment variability, soil conditions, FCCU turnaround schedule, start up costs, or construction climate. The EPA has considered including specific costs for offsites, soil conditions, turnaround schedule, equipment availability, climate, and startup in the costs estimates. Offsites include electricity, water, fire protection, steam, compressed air, and other utilities. The scrubber costs used by EPA to evaluate cost impacts include the cost of connecting utilities to the scrubber provided the utilities are located within the battery limits of the FCCU. The battery limits refer to that portion of the refinery associated with a particular process unit and its supporting equipment. Where utilities are not available or insufficient capacity is available within the FCCU battery limits, the refiner will incur a cost greater than that assumed in the cost estimates. However, a 20-percent contingency is provided in each capital cost estimate. The EPA considers that the site-specific costs related to soil conditions, turnaround schedules, site space and equipment availability, climate, startup, and the expense of offsites are included in this contingency and have, therefore, been considered by EPA.

In support of their comments on costs of construction climate, space and equipment availability, and pond and treatment system requirements, one commenter (IV-D-10) provided capital costs for the retrofit installation of a sodium scrubber to control both particulate and SO_x emissions from an FCCU at an existing refinery. The single alkali scrubber is sized for a flue gas volumetric flow rate similar to the 8,000 m^3/sd model plant used by EPA in developing costs. A comparison of the commenter's cost estimate with EPA's revised cost estimate shows that the total direct cost for both estimates is about the same. The commenter applied a 60-percent factor to account for indirect costs compared to the 40-percent factor used by EPA. The commenter also applied to this base cost estimate an additional 27-percent cost adjustment, which included labor productivity, design allowance, and construction climate. The EPA evaluated the commenter's cost factors and believes that these factors are adequately accounted for by EPA's 20 percent contingency cost factor (see the discussion of cost factors in this response). When adjusted to equivalent dollars, the commenter's cost estimate is approximately 50 percent higher than EPA's revised cost estimate for a comparably-sized single alkali scrubber installed on an existing FCCU.

The commenter's scrubber costs were developed from a preliminary factor-type cost estimate provided by a vendor. This type of cost estimate is developed in the early stages of a construction project when the project specifications are not very well defined. A factor-type estimate will typically contain several generous cost allowances to account for uncertainties in equipment specifications and construction. As a project becomes more defined, the final cost estimate normally is lower, and closer to the actual cost of the project. The EPA's costs are based on a vendor's experience with scrubber applications to FCCU's, and EPA believes that these costs are more representative of the actual cost of this scrubber design than the cost estimate provided by the commenter. Thus, the difference between the commenter's cost estimate and EPA's revised costs is largely due to the preliminary nature of the commenter's cost estimate.

One commenter (IV-D-20) indicated that EPA's cost estimates should more appropriately be based on the use of dual alkali FGD systems, because single alkali systems may not be applicable in areas where water availability or wastewater discharge is restricted. The commenter provided cost data to show that dual alkali systems are more expensive than single alkali systems. A dual alkali scrubber consists of two parts, the "front half" and the "back half." The front half of a dual alkali scrubber resembles a single alkali scrubber without a wastewater treatment unit and performs the same function--removing SO_x from a gas stream by contacting it with a caustic or soda ash scrubbing liquor. In the back half of a dual alkali scrubber, however, the purge is treated to regenerate the scrubbing liquor for reuse; a single alkali scrubber simply treats and discharges the purged liquor.

The EPA agrees that, where direct discharge of scrubber wastewater is not permitted, dual alkali scrubbers would be a viable alternative to single alkali scrubbers because dual alkali scrubbers produce a calcium sulfate sludge that would be more readily disposed than wastewater, but disagrees that dual alkali scrubbing systems would be more expensive than single alkali.

The commenter compared capital costs for dual alkali scrubbers to EPA's proposed single alkali scrubber costs. The commenter's cost estimates were based on proprietary actual scrubber cost information provided by the commenter's contractors. For each of the model plants presented in the proposal BID, a computer cost model was used by the commenter to estimate dual alkali scrubber costs assuming 90 percent SO_x reduction. The commenter's dual alkali scrubber costs are a function of volumetric gas flow rates and sulfur loading. The commenters cost estimates for dual alkali scrubbing were significantly higher than EPA's proposal estimates for all dual alkali model units.

Because these differences existed, EPA performed a further evaluation of dual alkali costs based on data from vendors of dual alkali systems (see Docket A-79-09, item IV-B-15). Specifically, Exxon's single alkali scrubber costs were used to develop costs for the front half of both sizes of a dual alkali scrubber. Environmental Elements Corporation provided back-half costs for both sizes of dual alkali scrubber. Also, Exxon provided EPA with a cost estimate provided to them by an independent vendor of dual alkali scrubbers for the back half of a dual alkali scrubber applied to the 8000 m^3/sd FCCU only. The commenter's and EPA's costs are based on a scrubber design that would control both FCCU particulate and SO_x emissions.

The EPA's revised capital cost estimates for dual alkali scrubbers are greater than those in the proposal BID, but less than Exxon's capital cost estimates for Exxon's single alkali scrubber. This is because the back half of the dual alkali scrubber, where the purged scrubbing liquor is treated to regenerate it for reuse, was found to be less costly than the wastewater treatment system needed to treat the purged scrubbing liquor before discharge from a single alkali system. Construction costs for the in-ground ponds specified by Exxon for wastewater treatment are greater than the cost of the dual alkali sludge dewatering and disposal facilities.

A comparison of EPA's revised dual alkali costs with those provided by the commenter shows that the commenter's total dual alkali costs remained significantly higher than EPA's revised dual alkali total cost estimate. However, because the commenter's cost information is based on proprietary actual cost data developed by contractors of dual alkali scrubbers and provided to the commenter, detailed cost information was not provided to EPA by the commenter, and a comparison of EPA's individual capital costs to those provided by the commenter was not possible.

The EPA's analysis of data supplied by vendors of dual alkali systems indicates that total single alkali scrubber costs are more costly than total dual alkali scrubber costs rather than less costly as the commenter believes. Therefore, EPA's current cost estimates for model plants, which reflect the use of only single alkali scrubbing, represent a conservative estimate of nationwide costs; dual alkali cost estimates applied to the model plants would only decrease the national costs. Therefore, it was decided not to revise costs of SO_2 control of model plants to reflect the use of dual alkali at some facilities.

This commenter (IV-D-20) also provided cost data for single alkali systems. The EPA performed an analysis of this single alkali cost data for comparison to single alkali cost estimates in the proposal BID (see Docket A-79-09, item IV-B-24). The commenter's costs for single alkali scrubber systems are similar to EPA's revised costs for the low sulfur model plants, but are significantly higher than EPA's revised costs for the 1.5 and 3.5 weight percent sulfur model plants. The commenter's single alkali cost estimates assume that single alkali capital costs are 93 percent of dual alkali costs. The EPA believes this approach is inappropriate because, whereas capital costs for dual alkali systems are a function of both waste gas flow rate and feed sulfur content, capital costs for single alkali systems are a function only of waste gas flow rate. Dual alkali control requires equipment to regenerate the reagent solution, the cost of which depends, in part, on the sulfur content of the flue gas. Because single alkali systems do not have such equipment, single alkali control costs are a function only of waste gas flow rate. Therefore, single alkali cost estimates derived by applying a constant percentage of dual alkali costs for different sulfur content models would result in erroneous estimates. The EPA believes, therefore, that the accuracy of the commenter's single alkali costs, which increase with feed sulfur content, is doubtful.

Two commenters (IV-D-9 and IV-D-20) stated that EPA needed to reevaluate the cost of retrofitting existing FCCU's with scrubbers. The EPA reevaluated these costs. Costs associated with retrofit will vary widely from one refinery to another based on the refinery configuration and the availability of land. In some cases, space limitations around an existing FCCU may result in relocating utilities and piping runs, longer ducting runs, and other factors that may make scrubber installations more difficult than at a new refinery. Therefore, EPA agrees that retrofit should be included in the cost estimates for some model plants. A retrofit cost factor of 20 percent of the scrubber capital cost (less contingency) was estimated by one commenter. This cost was added to three of the seven modified/reconstructed FCCU's anticipated to be subject to this standard over the next 5 years.

One commenter (IV-D-20) stated that EPA did not consider a cost for business interruption that would result from a scrubber malfunction shutting down the FCCU. Although sodium scrubbers have demonstrated reliability factors in excess of 95 percent (discussed in Section 3.2), scrubber malfunctions can occur. The General Provisions to 40 CFR 60 states that emissions in excess of an emission limit during a period of malfunction of a control device are not considered a violation provided the control device has been properly operated and maintained. During a period of a sudden or unavoidable scrubber failure, the refiner would still be able to operate the FCCU. Therefore, no business interruption cost would be incurred. For this reason, EPA did not include a business interruption impact when revising the proposal BID costs.

One commenter (IV-D-20) stated that EPA subtracted an ESP cost credit inappropriately in the cases of an existing FCCU with an ESP in place if scrubbers are required as a result of modification or reconstruction. The EPA agrees that an ESP cost credit is not appropriate in these cases. The proposal BID costs were revised to eliminate the ESP cost credit for the three modified or reconstructed FCCU's in which retrofit costs were included.

C. Summary of Cost Changes. As a result of both the general reevaluation of costs and of the review of specific cost comments, EPA revised the capital and annual cost estimates for FCCU scrubbers. The following changes were made: (1) costs of individual components were adjusted based on the data received; (2) JEV scrubber costs were revised to account for increased flue gas volume entering the scrubber as a result of CO boiler combustion air; (3) waste disposal costs were increased to include liquid waste discharges; (4) a cost for retrofit installation was added for of the modified or reconstructed FCCU's; and (5) the ESP cost credit was deleted for the three scrubbers that were installed on modified or reconstructed FCCU's and for which retrofit costs were included. Costs were then further adjusted to 1984 dollars.

After both the general and the specific cost analyses, EPA concluded that the proposal BID costs are not understated by a factor of 2.2 to 7. Results of the new cost estimates are presented in Appendix A of this document. Changes in cost as described above caused nationwide capital costs to increase by 30 percent (from \$72 to \$93.6 million); adjusted to 1984 dollars, capital costs increased a total of 63 percent from proposal (from \$72 to \$117 million). Changes in cost caused nationwide annual costs to increase by 5 percent (from \$35 to \$36.6 million per year); adjusted to 1984 dollars, annual costs increased a total of 29 percent from proposal (from \$35 to \$45 million per year).

Thus, these estimates show that the standards would result in a total nationwide capital cost for SO_x control for the first 5 years after the effective date of the standards of \$117 million, assuming sodium-based scrubbers are used at all facilities processing feedstocks with sulfur content above 0.3 weight percent. The fifth year nationwide annual cost is \$45 million. Units processing feedstocks with sulfur contents of 0.3 weight percent would be below the feed sulfur cutoff and therefore, would not need to install a scrubber. Where sodium scrubbers are not applicable, dual alkali scrubbers could be used at a similar cost to sodium scrubbers.

5.2 SO_x REDUCTION CATALYSTS COSTS

Comment:

Three commenters (IV-D-6, IV-D-9, and IV-D-20) wrote that the SO_x reduction catalyst technology requires a capital outlay. Two commenters (IV-D-6 and IV-D-9) stated that because the catalysts can only be used in units with HTR, older units subject to the modification or reconstruction provisions that do not or cannot operate in this mode will be required to convert or modify their units. This conversion could cost from $10-20 million per FCCU. The third commenter (IV-D-20) stated that although it may be true that the use of SO_x reduction catalysts would require little outlay for capital equipment, two exceptions would be: (1) a small refinery that does not have a sulfur recovery unit, and (2) a refinery with inadequate sulfur recovery unit capacity to handle the increased sulfur load due to the SO_x reduction catalyst technology. In either case, a capital expenditure would be necessary. Two of the commenters (IV-D-6 and IV-D-9) also stated that annual costs for SO_x reduction catalysts will likely be at least 2 times higher than EPA's estimate.

Response:

Many refiners have modified their older FCCU's to HTR. High temperature regeneration offers advantages over conventional regeneration (e.g., reduced SO_x emissions, improved yields, and increased throughput). It is unlikely that an older FCCU would become subject to these standards through the modification/reconstruction provisions without modifying the unit to HTR. A refiner is more likely to use SO_x reduction catalysts in an FCCU modified for HTR than modify an FCCU solely to use SO_x reduction catalysts. If an FCCU subject to these standards cannot utilize SO_x reduction catalysts, the refiner is more likely to select another control technique than incur a $10-20 million capital expenditure.

Use of SO_x reduction catalysts will increase the amount of H_2S in refinery fuel gas, which is removed from the fuel gas in a sulfur recovery unit. The increase in the amount of H_2S to a sulfur recovery unit is only about 5 to 10 percent. Sulfur recovery units generally are overdesigned by much more than this to account for swings or surges in H_2S production from refinery process units. It is doubtful that the use of SO_x reduction catalysts alone would overload a sulfur recovery unit. The EPA does agree, however, that in certain cases sulfur recovery unit capacity or a new unit would need to be added. These factors do not affect the reasonableness of the standards, however, since the standards are based on scrubbers as best demonstrated technology.

The EPA contacted companies developing or licensing SO_x reduction catalysts to obtain current costs for commercially available SO_x reduction catalysts. Catalyst developers reported costs for the technology ranging from \$0.60 to \$1.60/m^3 of fresh feed processed. The fifth year cost for SO_x reduction catalysts was then calculated by multiplying the cost factors provided by the catalyst developers by the total fifth year annual throughput for all affected facilities processing feedstocks containing greater than 0.30 weight percent sulfur. The new fifth year cost for SO_x reduction catalysts ranges from \$20 million to \$50 million. Costs for SO_x reduction catalyst are presented as a range because the technology is under development. The upper end of the range represents a newer catalyst formulation; the developer of this catalyst expects the cost to decrease as the catalyst formulation is produced in greater quantities.

5.3 ECONOMIC IMPACT ANALYSIS

Comment:

Several commenters (IV-D-3, IV-D-6, IV-D-9, IV-D-10, IV-D-15, and IV-D-20) stated that the proposed standards would have an adverse affect on the refining industry and the nation's economy. Four commenters (IV-D-6, IV-D-9, IV-D-15, and IV-D-20) wrote that the compliance costs are sufficiently high to require the preparation of a Regulatory Impact Analysis under Executive Order 12291. One commenter (IV-D-15) wrote that current prices will reduce the attractiveness of FCCU modifications to the point where the additional cost of a scrubber or other SO_x control device would not be feasible. Three commenters (IV-D-3, IV-D-9, and IV-D-10) wrote that the costs of the proposed standards would, in some cases, postpone new investments and would cause a significant economic impact on the profitability of FCCU operation and construction of new FCCU's.

Response:

The cost analysis presented in the proposal BID was reviewed under Executive Order 12291 by the Office of Management and Budget (OMB). Since that time, in response to comments, EPA has revised these costs upward. This latest cost revision is presented in Appendix A. With these revisions, the fifth year nationwide annualized costs are still below the $100 million level that triggers a regulatory impact analysis under Executive Order 12291. The price increases published in the proposal BID were all less than 0.4 percent. Using the revised control costs and second quarter 1984 product prices, that figure increases to approximately 0.8 percent for the worst case considered (3.5 weight percent sulfur feedstock). The EPA still considers this to be acceptable.

The capital required for the control devices will increase the investment for a new FCCU by 9 percent for the 8,000 m^3/sd unit and by 15 percent for the 2,500 m^3/sd unit. The EPA does not consider these percentages sufficiently high to deter a decision to install an FCCU that is otherwise economically justified.

Comment:

One commenter (IV-D-16) suggested an exemption for refineries classified as small businesses because EPA had stated in the proposal BID that due to the discontinuance of the entitlements program, very little construction is anticipated at small refineries. Therefore, the percentage of small refining businesses affected will be well below the level of concern. The commenter seemed to interpret this statement to mean insignificant emissions and suggested that small refineries should be exempt for that reason.

Response:

The EPA does not consider the potential emissions from small refineries to be insignificant. Scaling down emissions from EPA's model FCCU sizes to a unit of the size discussed below (950 m^3/sd) indicates that, even with a low sulfur feedstock, emissions would be greater than 100 Mg SO_x/yr. Therefore, EPA would not exempt small refineries because of insignificant emissions.

A recent investigation has revealed that 14 of the 116 refineries that currently operate FCCU's are classified as small refiners, i.e., less than 1500 employees and less than 8000 m^3/sd crude oil refinery throughput. The EPA guidelines require that a Regulatory Flexibility Analysis should be performed if more than 20 percent of the small business sector will experience a significant adverse economic impact. The EPA continues to believe that, due to the discontinuance of the entitlements program, very little construction is anticipated at small refineries. However, EPA examined the impact that the regulations would have on a small business.

To examine that impact, EPA selected from the 1984 Oil and Gas Journal Annual Refining Survey, the FCCU representing the low 20th percentile throughput of the population of currently operating small refineries, which was an 950 m^3/sd FCCU in a 1,350 m^3/sd refinery. To approximate the impact on revenue and production costs, EPA used the control costs in Appendix A and the revenues on page 9-34 of the proposal BID scaled down to the refinery size with revenues reduced to reflect a 19 percent drop in product prices. The compliance cost as a percent of sales revenue amounted to less than one and one-half percent. The same was true of compliance costs as a percent of production costs. To install an FCCU of this size under these standards would cost an additional 15 percent to provide scrubber controls. Furthermore, EPA does not expect any small refineries to close as a result of this action. Therefore, EPA does not feel that the differential impact between large and small refiners is significant enough to justify an exemption based on unit size.

6.0 COMPLIANCE TESTING AND MONITORING COMMENTS

6.1 GENERAL

Comment:

One commenter (IV-D-11) pointed out that the preamble to the proposed standards states that SO_x testing is conducted upstream of the CO incinerator while velocity and volumetric flow rates are determined downstream of the CO incinerator. The regulation indicates that sampling for SO_x concentration "shall be the same as for determining volumetric flow rate." The commenter believed the regulation statement is correct.

Response:

The EPA agrees with the commenter; SO_x testing should be performed at the same location as the volumetric flow rate measurement, as is specified in the regulation.

Comment:

One commenter (IV-D-20) pointed out that the proposed regulation states that sampling should be conducted upstream of the CO boiler. The commenter stated that it is unsafe to require personnel to conduct manual sampling due to the high flue gas temperatures at this location (650-769°C). Additionally, sampling at extreme temperatures is impractical due to frequent sampling train operating problems and rapid sample probe failures.

Response:

The EPA recognizes the commenter's concern regarding safety. Sampling either upstream or downstream from the CO boiler is acceptable for the standard without add-on controls. However, if the owner or operator chooses to test downstream of the CO boiler, alternative calculation procedures for determining the coke burn-off rate and the SO_x contribution due to the auxiliary fuel burned in the boiler must be submitted to and approved by the Administrator prior to sampling. In addition, the recommended location for the inlet CEMS has been changed to downstream of the CO boiler for the standard with add-on controls.

Comment:

Seven commenters (IV-D-2, IV-D-3, IV-D-6, IV-D-7, IV-D-9, IV-D-16, and IV-D-20) requested the inclusion of alternative methods in the standards to be used to determine excess emissions. A number of commenters (IV-D-2, IV-D-3, IV-D-6, IV-D-7, IV-D-9, and IV-D-20) suggested conducting periodic performance tests to determine excess emissions. One commenter (IV-D-2) also suggested periodic (weekly) monitoring or the establishment of a relationship between feed sulfur or sulfur on the spent catalyst and emitted SO_x emissions. Another commenter (IV-D-3) also suggested the determination of a relationship between feed sulfur and coke sulfur. One commenter (IV-D-16) suggested establishment of a trigger-level value (T) that would be derived from the compliance test value (C) multiplied by the ratio of actual feed sulfur during the 3-hour report period (A) to the feed sulfur during the compliance test (S): $T = CA/S$.

Response:

The standards now require compliance to be determined on a daily basis. The methods proposed by the commenters for excess emissions are not reasonable methods to use for determining compliance on a daily basis because they do not generate data sufficiently accurate for compliance (vs. excess emissions) determinations.

6.2 WITH ADD-ON CONTROL DEVICES

Comment:

One commenter (IV-K-1) stated that an operator of an add-on control device should be given the flexibility to choose between the original proposal, which would have required using an outlet monitor only, and the operation of a CEMS in which both an inlet and outlet monitor are used. The commenter supported this by suggesting that the advantages of continuous inlet monitoring would not justify the additional cost over the most recent compliance test if the feed to the FCCU is not highly variable. The commenter stated that, where the feed sulfur content is expected to be highly variable, the operator may benefit from using both an inlet and outlet monitor to demonstrate compliance with the standard.

Another commenter (IV-K-2) stated that, during the compliance test for the standard for add-on controls, a measurement at both the inlet and the outlet is needed. However, after the compliance test, the proposed standards only need an "alerting service," which could be provided by an outlet monitor alone.

Response:

The standard for FCCU's using add-on controls is 90 percent reduction or 50 vppm, whichever is less stringent. The intent of monitoring for the standard for add-on controls is to determine compliance on a daily basis, as described in the revised proposal. To meet this intent, the Agency needs data that show the actual compliance status of the source, not data that simply alert the Agency to potential problems, and to make an accurate determination of compliance with the 90 percent reduction standard, the Agency must have both scrubber inlet and outlet data. Even where feed sulfur is not "highly" variable, the outlet concentration may vary due to FCCU operation or the source of the feed, while scrubber performance may stay constant. Therefore, measuring only the outlet emissions may lead to an incorrect compliance determination for the percent reduction standard. The Agency recognizes, however, that an inlet monitor is unnecessary for making continuous compliance determinations in relation to the 50 vppm standard for add-on controls. Thus, the Agency has modified the regulation so that owners or operators may choose to declare their intent to meet the standard for add-on controls by limiting their outlet SO_2 emissions to 50 vppm and install a CEMS at only the outlet of the control device to determine compliance. The Agency wishes to point out that, for such owners or operators, compliance determinations will be made only on the basis of the outlet SO_2 emissions without regard for the percent reduction being achieved by the control device. Such owners or operators may change their choice so they would be subject to the whole standard on "90 percent reduction or 50 vppm, whichever is less stringent," provided a CEMS is installed and maintained at the inlet of the control device as well as the outlet.

Comment:

Several commenters (IV-D-3, IV-D-6, IV-D-9, IV-D-11, and IV-D-16) recommended that the outlet CEM requirements should be eliminated for the standard for add-on controls because CEMS are an unsuitable means to indicate compliance (determine excess emissions). Three commenters

(IV-D-3, IV-D-6, and IV-D-9) stated that a post-scrubber CEMS is unsuitable to indicate scrubber performance due to large variations in scrubber inlet SO_x concentrations. Therefore, the scrubber outlet SO_2 concentration established during the performance test cannot be expected to indicate compliance with the SO_x emission standard over extended periods of operation. Three commenters (IV-D-6, IV-D-11, and IV-D-16) cited that the outlet SO_2 concentration measured during the performance test of the scrubber and used to define excess emissions is relatively meaningless since it would be very difficult to determine a "representative" feed. Two commenters (IV-D-6 and IV-D-9) also stated that the outlet SO_2 concentration level measured during the scrubber performance test could very likely correspond to a scrubber efficiency better than the standard as there exists a strong possibility that the scrubber would be operating at a reduction efficiency greater than 90 percent during the performance test. One commenter (IV-D-6) noted that using an SO_2 concentration level to indicate scrubber performance is unsuitable because the method does not take into account the variation of the relationship between SO_3 and SO_2 over time and over the range of feedstocks to be used. Finally, one commenter (IV-D-11) stated that the outlet-monitor approach cannot compensate for changes in flue gas volume. The commenter recommended that an SO_2 monitor upstream of the scrubber is necessary to indicate scrubber performance.

Response:

At proposal, affected facilities complying with the standard for add-on controls were required to maintain a continuous SO_2 monitor at the scrubber outlet, and excess emissions were determined based on a trigger outlet concentration level established during the initial performance test. In the revised proposal, EPA proposed that the standard for add-on controls has been changed to require daily compliance determinations of the percent reduction being achieved by the add-on control device. Therefore, the regulation has been revised to require the installation of a scrubber inlet and outlet SO_2 monitor for owners or operators who elect to comply with the standard for add-on controls. (An owner or operator who seeks to comply solely with the 50 vppm standard, as discussed in the previous comment, is required to install only an outlet CEM.) Thus, the situation described by the commenters is eliminated.

Comment:

One commenter (IV-D-16) stated that since an excess emission report only triggers awareness, the method of determining excess emissions specified under 40 CFR 60.105(e)(3)(iii) need not be precise, and thus, adjusting to an oxygen-free basis is unnecessary.

Response:

The standards now require determination of compliance, on a daily basis, rather than determination of excess emissions. Compliance determinations have a greater need for precision than excess emission determinations because the former are used to determine whether or not a source is in compliance while the latter are used to trigger awareness that a source may not be in compliance. Therefore, the oxygen-free basis has been retained.

Comment:

One commenter (IV-K-9) felt that because an add-on control device achieves greater reductions in SO_2 emissions than technologies meeting the standard without add-on controls, "less drastic" compliance monitoring requirements for scrubbers are reasonable. The commenter referred to Subpart GGG, 40 CFR Part 60, as an example for this approach in which pumps with dual mechanical seal systems that include a barrier system fluid are exempt from monthly VOC monitoring requirements to detect leaks. This commenter proposed that compliance be determined instead by an initial performance test, quarterly monitoring of inlet and outlet SO_x concentration using EPA Reference Method 6 or 6B, and continuous monitoring of wet gas scrubber process variables, such as pH, liquid-to-gas ratios, and pressure drop, to evaluate scrubber performance in an ongoing basis.

Response:

Monitoring and testing requirements are chosen to be appropriate for the control technique and to meet the intent or goal of the monitoring and testing. The relative stringency of different control techniques has no bearing on the selection of the most appropriate monitoring or testing requirement for each control technique. The example in Subpart GGG referred to by the commenter is not appropriate.

For pumps without dual seals, monthly leak detection and repair is the control technique; that is, the monthly monitoring is not to monitor how well the control is doing, but rather it is the control. The dual seals for pumps are an alternative control technique. Therefore, the "exemption" for monthly leak detection and repair is not a monitoring exemption but a means by which an owner or operator does not have to use two control techniques. The testing requirement for dual seals was determined based on its appropriateness to the control technique.

The purpose of monitoring for these standards is determining compliance on a daily basis. Therefore, the Agency must collect data on each control technique from which compliance can be determined. The procedure suggested by the commenter may give information on the operation of the scrubber, but it does not give information from which the compliance status can be determined.

In summary, the Agency has determined that the monitoring requirements for scrubbers are appropriate for determining continuous compliance and that the arguments and the proposed change offered by the commenter are unfounded to support a change.

Comment:

Several commenters (IV-D-2, IV-D-3, IV-D-6, IV-D-7, IV-D-16, IV-D-20, IV-K-2, and IV-K-9) stated that continuous SO_2 monitors are unreliable due to monitor operational problems. Problems noted included generation of imprecise and inaccurate data, zero and span drift, intensive operator attention, excessive sample system plugging, and unreasonable maintenance requirements.

One commenter (IV-K-9) proposed that the requirement for continuous monitoring of the inlet and outlet to add-on controls be eliminated. This commenter expressed concerns about the operability of an outlet CEMS, stating that utility FGD experience has shown that it is very difficult to maintain the analyzer in a saturated gas stream. This commenter and Commenter IV-K-2 also expressed concerns about the operability of an inlet CEMS, stating potential difficulties due to particulate plugging of the analyzer. Commenter IV-K-2 stated that, to his knowledge, EPA does not have CEMS data showing that the device can run 24 hrs/day for one full month and give accurate results. This commenter referred to the gaps in the monitoring by a CEMS in each of the first 10 days in Figure C-1 of the BID for the proposed standards. Commenter IV-K-2 also asked how CEMS reliability was proven, and what CEMS sample collecting and conditioning systems were used to prove CEMS reliability.

Response:

The EPA extensively studied the reliability of SO_2 and diluent CEMS during the development of Subpart D, Subpart Da, and Appendix F of 40 CFR 60. Current studies show that state-of-the-art monitoring systems provide precise and accurate data when proper operation and maintenance techniques are employed on a continuous basis. Experience has shown that approximately 2 hrs/day of manual attention is necessary to obtain an 85 percent or greater availability. Further, as discussed in the BID for the proposed standards, Appendix D, FCCU catalyst regenerator exhausts are similar to those of coal-fired steam generators; therefore, the continuous SO_2 monitoring technology proven acceptable for steam generators should be applicable to FCCU catalyst regenerators. Sulfur dioxide monitors have been installed on some FCCU catalyst regenerators; EPA has gathered information on the operational history of some of these CEMS but the data were insufficient to compare directly to Appendix F, Procedure 1, to 40 CFR Part 60, which contains quality assurance procedures for CEMS used for compliance determinations.

The Agency has, for example, conducted tests at an Exxon wet gas scrubber using inlet and outlet SO_2 CEMS (see Docket A-79-09, item II-A-18A). The outlet monitor was on a saturated gas stream without reheat of the flue gas. There was no particulate removal in the flue gas prior to the inlet monitor. The duration of the testing was about 12 days. Over this time, no difficulty was experienced in obtaining valid data. Some regular backflushing of the outlet analyzer system occurred due to the saturated nature of the flue gas. This limited time testing suggests that with careful maintenance of the monitors, long term use and potential problems can be avoided. The difficulty stated with regard to outlet monitors on a saturated gas stream can be overcome through adequate design and maintenance of the CEMS. (The commenter does not state that the difficulty cannot be overcome, but rather just that it is difficult.)

The Agency does not agree that particulate plugging will be a "fatal" problem. In-stack filters have been redesigned with better shields and improved outside-stack conditioning systems have been developed that allow removal of the in-stack filter, when necessary. Furthermore, technologies are available to circumvent CEMS plugging. Properly designed systems usually have back-purge capabilities to prevent particulate plugging of the sampling probe in the stack. Studies have also shown that high pressure (greater than 70 psi) air in backflushing sample lines and probes improves removal of particulate and moisture from the in-stack probes and filters both upstream and downstream of scrubbers. Manufacturers of the systems and installation personnel would be responsible for designing each system for a specific source. Proper design along with consistent and proper maintenance should be able to prevent particulate plugging to the extent that an owner or operator will be able to obtain the minimum data requirements.

Based on these studies, EPA has concluded that continuous SO_2 monitors are reliable and accurate when properly operated and maintained (see Docket A-79-09, item IV-J-1), and are capable of meeting the minimum requirements for determining compliance with these standards. Thus, the promulgated standards retain the requirement for continuous SO_2 monitors. The EPA does not expect the CEMS to run nonstop for 24 hrs/day for an entire month. The minimum data requirements (i.e., collection of 18 valid hours of data per day for 22 days out of every 30) provide for downtime. This provides the owner or operator time to maintain and calibrate the CEMS and correct minor malfunctions.

Comment:

One commenter (IV-K-2) asked why EPA bases the NSPS on an "undeveloped" continuous emission monitor. The commenter referred to the proposed Section 60.106(e)(2) which requires SO_2 CEMS's at the control device inlet and outlet to determine kg of SO_2/hr values, while BID Appendix D, p. D-13, says that the accuracy of a similar CEMS used to calculate kg of SO_2/kg of coke is unknown.

Response:

The commenter is confusing the reliability of two different CEMS's. The "similar CEMS" referred to by the commenter that is in Appendix D of the BID for the proposed standards, p. D-13, is a CEMS that is to obtain an estimate of both kg of SO_2 and 1,000 kg of coke burn-off. The latter estimate requires measurement of 10 to 12 parameters and the BID clearly states that measurement of this many variables introduces serious questions as to the accuracy of the resulting estimate. It is this CEMS, which tries to estimate kg SO_2/1,000 kg of coke burn-off, that is considered unreliable. However, the standards for add-on controls do not require measurement of coke burn-off. Rather, the standard for FCCU's requires that SO_2 emissions be measured in parts per million by volume (vppm) at both the inlet and outlet to the scrubber or other add-on control device. Such a format requires the measurement of at most two parameters, SO_2 emissions and diluent O_2 or CO_2 emissions. The reliability of the SO_2 and diluent O_2 or CO_2 CEMS's has been demonstrated and performance specifications for evaluating the acceptability of these monitoring systems in this format are deemed adequate as specified in 40 CFR Part 60.13 (46 FR 8352, January 26, 1981) (see Docket A-79-09, item II-J-2). In summary, the comparison the commenter tries to make is inappropriate. Continuous emission monitors are available that have the reliability and accuracy to meet the needs of the standard for add-on controls.

Comment:

One commenter (IV-K-3) recommended an increased allowance for CEMS downtime and maintenance, such as requiring data for 15 days per month instead of 22, and 12 hrs/day instead of 18. The commenter stated that the company has limited commercial experience on one FCCU with a CEMS installation they believe is reasonably successful (installed less than 1 year). The installation is downstream of a CO boiler and an ESP. According to the commenter, a CEMS placed upstream would be subject to much more severe service because of its exposure to hot catalyst fines and a higher SO_x concentration than that seen by a downstream analyzer. The commenter added that sampling performed by an upstream CEMS would be more complex, and the CEMS would be expected to have a lower operating factor.

Response:

In requiring the use of CEMS's for determining compliance, EPA based its selection of 18 hours of data in a 24-hour day and 22 days of data out of 30 days on the minimum data requirements for compliance determinations specified for utility boilers under Subpart Da of 40 CFR Part 60. Under these standards, EPA concluded that the required data to be collected provided sufficient information to characterize emissions, and that properly operated and maintained CEMS's were capable of meeting these requirements. The operating conditions at the upstream CEMS at FCCU's are similar to those found at a Subpart Da boiler CEMS prior to the flue gas scrubber.

Comment:

One commenter (IV-K-2) asked whether EPA planned to require an approved manual emission test twice an hour, 18 hours a day, at times when the CEMS fails. If a manual emission test is needed, this commenter asked how long the revised Method 8 takes to perform.

Response:

No manual testing would be required when the CEMS fails provided the facility meets the minimum data requirements specified by EPA. Minimum data requirements were established to allow for periods when CEMS's are shut down for various reasons but limit the amount of data permitted to be lost before supplemental sampling is required. These requirements provide time for CEMS maintenance and calibration and correction of minor malfunctions. Malfunctions are not likely to occur every 30-day period. Thus, EPA expects that most CEMS's routinely will operate better than the minimum data requirements and supplemental sampling will be rarely necessary to meet them.

Many methods are available for supplemental sampling; each owner or operator would develop his approach to obtaining these minimum data in the Quality Control Plan required by Appendix F, Procedure 1. Any acceptable sampling scheme, such as Method 8, would have to obtain data representing at least 18 hours of operation daily. Method 8 is unlikely to be used, however, because it measures SO_x when only SO_2 data need to be obtained. Methods 6 and 6B are more likely to be used. If Method 6 is used, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average. To obtain one valid day from supplemental sampling requires 18 valid samples. Method 6B, if used, would also have to collect a sample representing a minimum of 18 hours. If a back-up monitor is used instead, then a minimum of 18 valid hours to obtain a valid day is still required.

Comment:

One commenter (IV-K-2) believes that neither Method 6 nor 6B can be used to supply back-up data when the CEMS fails because: (1) Methods 6 and 6B have sampling problems and poor reliability, and (2) temperatures above 120°C are forbidden when using either method (see 49 FR 9684 for Method 6A and 49 FR 9686 for Method 6B). The commenter pointed out that the EPA has stated that at least 160°C is needed when testing.

Response:

The commenter is concerned with the test methods (6 and 6B) that may be used to gather supplemental data in order to meet the minimum data requirements for the standard for add-on controls. The 160°C temperature referred to by the commenter is required when using Method 8, which is used in determining compliance with the standard for FCCU's without add-on controls. Thus, the commenter's concern about Methods 6A and 6B limiting probe temperature to 120°C is irrelevant to the 160°C probe temperature identified for Method 8.

The Agency believes that the commenter's concerns about sampling problems and poor reliability have been addressed by the changes made to these methods as reported in 49 FR 9684. These two methods are possible means by which an owner or operator can supplement occasional missing data and are not the only means available to the owner or operator. Details of the actual procedure(s) chosen by the owner or operator would be provided in the Quality Control Plan required by Appendix F, Procedure 1.

Comment:

One commenter (IV-K-2) suggested that the 7-day average performance of the control device be calculated using the individual daily averages of the CEMS data, rather than all of the valid hours within the 7-day period. The commenter felt this should be done in order to prevent an operator from "bunching up" valid CEMS data points on "good" days and taking minimum measurements on "bad" days.

Response:

The deliberate actions on the part of an owner or operator described by the commenter would clearly be seen as an attempt to circumvent the standard and such circumvention is illegal, prohibited by the NSPS General Provisions in Subpart A, Section 60.12 of 40 CFR Part 60. Further, the minimum data requirements (i.e., requirement to collect 18 valid hours out of every 24 hours) will limit the potential for showing a source to be in compliance when the source would actually be out of compliance if bunching did not occur. Therefore, the Agency does not believe it necessary to change the method of averaging data for determining daily compliance when using the add-on controls and has retained the averaging of all valid hours.

Comment:

One commenter (IV-K-2) suggested that the Agency require averaging daily percent reduction values when calculating the 7-day rolling average rather than averaging inlet and outlet data separately. The commenter, in making this suggestion, pointed out that the time series model was analyzed in terms of percent values and, through a sample calculation, that averaging percent emission reduction values provides a more stringent emission standard.

Response:

The Agency considered both averaging daily percent reduction values and averaging inlet and outlet data separately when calculating the 7-day rolling average. Calculating a daily average of hourly percent reductions requires both monitors to be operating at the same time for a minimum of 18 hrs/day to obtain a valid day. Averaging inlet and outlet data separately allows a little more leeway in the time that either monitor is not functioning before back-up measurements or monitors are needed.

Further, the Agency found little difference (less than 0.4 percent) in the calculated rolling 7-day percent reduction value using the two methods described by the commenter for the data used in the time series analysis (see Docket A-79-09, item IV-B-13). In addition, the example calculation provided by the commenter to show a "more stringent" standard is insufficient as the Agency can easily construct an example showing the opposite result.

In summary, the Agency believes the averaging of inlet and outlet data separately adequately and accurately determines compliance, and does so with the potential of cost savings to affected owners and operators by decreasing the need for using back-up measurement methods.

Comment:

Two commenters (IV-K-2 and IV-K-9) questioned the costs of CEMS's reported by EPA. One commenter (IV-K-2) asked whether the sample collecting and conditioning systems needed to ensure a reliable CEMS were included in the price of the CEMS. This commenter questioned the cost of $40,000 in the preamble for the additional CEMS, as BID Table D-1 gives a cost of a CEMS as $59,000 to $80,000 (1981 dollars), and asked whether the Agency updated the costs from the original proposal. The second commenter (IV-K-9) felt the Agency substantially underestimated the costs of a CEMS. This commenter estimated that the total cost (analyzer, sampling system, and installation costs) would be about $100,000 per analyzer for an extractive system and about $150,000 to $175,000 per analyzer for an across-the-stack system. This commenter also estimated the annual maintenance manpower costs to be about $16,000 for an extractive system and about $2,000 for an across-the-stack system. The second commenter also stated that the estimate of $40,000 for the additional monitor appears to reflect only the cost of the analyzer and not the sampling system and installation costs. This commenter felt that the proposed requirement for continuous monitoring at the inlet and outlet to add-on control devices be eliminated because of the cost of CEMS's.

Response:

The cost of the additional CEMS reported in the revised proposal notice reflected the cost of an extractive analyzer and installation (in February 1981 dollars). The Agency updated the original 1981 costs for the extractive analyzer system and obtained a revised fourth quarter 1984 cost estimate of $69,300 (including installation and data acquisition system (DAS); $46,200 without the DAS).

The Agency also recently attempted to obtain updated CEMS cost data by contacting vendors and source owners or operators using CEMS (see Docket A-79-09, item IV-A-1). The study found "worst-case" vendor costs for an SO_2/diluent extractive system from $43,000 to

\$100,000 (1984 dollars). (The worst-case costs included additional costs for longer sample lines, corrosion-resistant probes, probe backflush systems, and computer data acquisition systems capable of generating emissions reports.) Worst-case installation costs (which are for an SO_2/NO_x/diluent CEMS) ranged from \$2,000 to \$80,000. Total worst-case costs for an extractive analyzer would be from \$45,000 to \$180,000 (including a DAS and installation). "Best-case" costs for an extractive analyzer system, including installation, ranged from \$15,400 to \$86,000. The commenter provides an estimate of about \$100,000 (analyzer, sampling system, and installation). Taking out the cost of a DAS (about \$23,100) from the worst-case costs, the commenter's estimate falls in the middle-to-upper end of the worst-case costs. The Agency notes that its original cost estimate for an extractive analyzer, when updated to 1984 dollars, still falls within the worst-case costs range reported in the updated study.

The across-the-stack cost estimate (\$40,460) obtained in February 1981 was for a complete outlet monitoring system to which the Agency added a cost of \$20,000 for installation and \$20,000 for a DAS. Total cost, including installation, for the outlet monitor was, thus, \$80,400 (February 1981 dollars). Updating this cost to fourth quarter 1984 dollars yields a cost estimate of about \$92,900 for the analyzer, DAS, and installation. Data on across-the-stack CEMS gathered more recently show worst-case vendor estimates for an SO_2/diluent CEMS (including a DAS) to range from \$44,000 to \$96,000, with installation ranging from \$2,000 to \$80,000. Assuming a DAS cost of \$23,100, total worst-case costs without a DAS would be from \$22,900 to \$153,000. Best-case condition costs were estimated to be \$34,400 to \$60,000 per analyzer (\$34,000 to \$45,000 for the analyzer plus a DAS, plus \$400 to \$15,000 installation). Commenters IV-K-9 estimated costs of about \$150,000 to \$175,000 per analyzer (analyzer, sampling, and installation), which falls in the upper range of the worst-case vendor estimates.

The annual maintenance costs estimated by the Agency in the proposal BID Appendix D were \$11,000 for either an extractive or across-the-stack CEMS. Updating the cost results is an estimate similar to the commenter's estimate of \$16,000 for an extractive system and is more conservative than the commenter's estimate for an across-the-stack system.

6.3 WITHOUT ADD-ON CONTROL DEVICES

Comment:

Several commenters (IV-K-3, IV-K-4, IV-K-6, and IV-K-12) stated that EPA had underestimated the costs of daily Method 8 testing. One commenter (IV-K-4) believes that annual expense for labor to collect and analyze daily Method 8 samples would be about $300,000/yr. This commenter specifically indicates that this cost assumes no automatic traversing system is used, but all testing is accomplished manually. The commenter estimated that daily sampling would require a full-time 3-person (supervisor and 2 assistants) stack testing crew, which would be responsible for testing, repair, and maintenance of the trains, calibration checks, analyses, etc. This commenter also stated that a back-up crew would be necessary. Commenter IV-K-3 estimated the operation and maintenance cost to be about $250,000/yr. This commenter assumed, in part, that sixteen samples would be required each day and analyzed at 15 minutes per sample. This commenter used vendor labor hour rates to estimate the labor charges. Commenter IV-K-6 estimates that daily Method 8 sampling, using a contractor, would be about $400,000/yr. This commenter estimated daily labor hours to be 8 hours for sampling and analysis apiece and 12 hours for preparing the reports and project management. Commenter IV-K-12 estimated that the total annual cost would be about $184,000 per FCCU. This commenter believes that 4 man-years of effort would be required and based the cost on 3 technicians (each at $41,600/yr) and 1 professional (at $58,800/yr).

Another commenter (IV-K-2) asked how EPA determined yearly costs of Method 8 to be "reasonable" when the costs are unknown? The commenter did not think it was reasonable to claim the costs to be "reasonable" when the costs are based, in part, on a traversing system not yet developed. The commenter also asked the Agency to identify the cost of revised Method 8 and what the cost would be if you did not have an automatic traversing system. Commenter IV-K-3 questioned EPA's assumption that an automatic traversing system can be readily developed and implemented. This commenter noted that adding equipment such as an automatic traversing system will increase system complexity and that problems with an automatic traversing system (such as binding) may be significant and degrade on-stream factor.

Another commenter (IV-K-4) stated that the daily manual stack testing requirement using EPA Method 8 for SO_x emissions determination is premature, pointing out that because no means of automated performance of this test exists, it must be performed manually. According to this commenter, future development of an automatic traversing system is speculative and unfounded given the technical complexity of the stack testing protocols involved.

Response:

The standard requires one 3-hour sample per day, 365 days per year. As noted in the comment summary, one commenter states explicitly that they calculated their labor costs assuming no automatic traversing system. The Agency believes that the other commenters made the same assumption. After further consideration, the EPA has agreed with the commenters that the assumption of an automatic traversing system should not be used for evaluating and recommending daily Method 8 testing, although the Agency still contends that it is technologically feasible.

Instead, the Agency has revised the cost estimate assuming that a monorail system will be installed at each of the two sampling ports and that a single sampling train will be used, with manual movement of the sampling train for traversing and changing ports (see Docket A-79-09, item IV-B-12). Although not addressed by the commenters, EPA decided that it was appropriate to also include a cost for an enclosed sampling area to protect the sampler and equipment from various weather conditions, such as rain and snow. The capital cost of the monorail system and enclosure is estimated to be $20,000. When the Agency originally estimated the cost using an automated traversing system, we assumed two sampling trains, one in each port. With the revised assumptions, only one sampling train is used, and moved from one port to the next; this halves the number of samples to be analyzed to 365 (1 per day).

The EPA disagrees with the commenters' claim that 3 or more people would be devoted full-time to this stack testing. Only one 3-hour sample is required each day. The Agency believes that it would take an average of 8 labor hours per day to prepare the equipment, conduct the sampling, and perform periodic maintenance on spare equipment, with an added labor for analysis of about 1.3 hours per sample. This estimate is the same or similar to that assumed by Commenter IV-K-6 and, when adjusted for the number of sample points, by Commenter IV-K-3. The Agency estimated that the quarterly reports would take about 50 hours each to prepare. This is equivalent to less than one hour per day. The Agency strongly disagrees with the 12 hour per day estimate used by Commenter IV-K-6. On the basis of the above assumptions and revisions, the revised annualized cost per affected facility is estimated to be $120,000.

Comment:

Many commenters (IV-K-1, IV-K-2, IV-K-3, IV-K-4, IV-K-5, IV-K-6, and IV-K-8) stated that daily testing should be deleted from the standard for FCCU's without add-on controls. The commenters felt that daily testing was too costly and unduly burdensome, especially, according to one commenter (IV-K-4), when compared to the costs of monitoring for the scrubber or testing under the feed hydrotreat option.

One commenter (IV-K-3) stated that he knew of no other instance in which this type of non-routine sampling is being performed on a daily basis to satisfy compliance requirements. This same commenter also stated that, in general, direct compliance information should not be required if, in the course of obtaining it, an unreasonable cost burden occurs. Commenter IV-K-3 also states that the cost of daily Method 8 testing will impose a disproportionate hardship on small FCCU's, as the costs are independent of unit size.

Commenter IV-K-1 stated that the cost of daily Method 8 testing could hamper improvements in SO_x reduction catalyst development and felt that the estimated cost of $130,000/yr would put an onerous burden on FCCU operators who choose to develop and use SO_x reduction catalysts.

A third commenter (IV-K-6) stated that the economic impact is significant and would affect the profitability of FCCU operation. This commenter noted that the corporation operates 9 FCCU's and claimed that they would have to spend approximately $3.6 million/yr to conduct daily Method 8 testing.

Response:

The Agency recognizes that daily testing with Method 8 is not inexpensive, but that it is also not an unreasonable cost. The Agency has examined various methods available to show daily compliance with the standards. For facilities that opt to use SO_x reduction catalysts to meet the standards, the Agency has determined that daily Method 8 testing is currently the only viable alternative that enables the Agency to be sure that the owner or operator is in compliance on a daily basis.

The relative costs of the various methods for determining continuous compliance available to all affected facilities subject to the standards is not a valid basis for rejecting one method or another, just as the relative costs of the capital investment of the various control options are not a basis for excluding one or the other. What is relevant is whether the total (capital, annual, monitoring, etc.) cost of compliance for meeting the standards for an affected facility is reasonable or unreasonable. Similarly, the lack of other situations requiring similar "non-routine" sampling is not a valid basis for eliminating this requirement. Daily testing is needed for this standard in order to show daily compliance.

The Agency disagrees that the burden is "unreasonable" or "onerous," the economic impact is "significant," or the profitability of FCCU operation will be adversely affected. The Agency studied the potential economic impact of the standards on small and large refineries and reported and discussed the findings in the original proposal notice to these standards (49 FR 2072). The economic impact to the small (and large) refiner is expected to be small because most, if not all, of the cost should be capable of being included in the prices of the refined petroleum products and the resulting price impact is reasonable. These results were obtained assuming compliance by all projected affected facilities with the standard for FCCU's with add-on controls, which is more expensive than compliance with the standard for FCCU's without add-on controls. Therefore, the economic impacts of complying with the standard for FCCU's without add-on controls will be smaller.

The Agency believes that the monitoring costs associated with daily Method 8 testing are unlikely to affect SO_x reduction catalyst development. Even with the higher monitoring costs, SO_x reduction catalysts are still likely to be the least expensive route to meeting the standard. Thus, development on SO_x reduction catalysts will still continue as owners or operators try to minimize their costs in meeting these standards.

The third commenter's estimate of $3.6 million assumes: (1) all 9 FCCU's will use SO_x reduction catalysts and (2) the cost per FCCU for daily Method 8 testing is $400,000 per FCCU. The Agency believes both are highly unlikely to occur because: (1) we do not expect all FCCU's (e.g., such as those with very high sulfur feed contents) to use SO_x reduction catalysts and (2) the commenter overestimates the cost of daily Method 8 testing (see response to the previous comment).

In conclusion, the Agency believes that the cost of daily Method 8 testing is reasonable in order to ensure daily compliance. Less expensive methods that allow the Agency to make equivalently accurate daily compliance determinations are encouraged and may be used subject to the approval of the Administrator.

Comment:

One commenter (IV-K-4) stated that daily stack testing is an unduly burdensome requirement and added that EPA has not provided a sufficient basis to justify such an extraordinary requirement as daily stack testing. According to this commenter, daily manual stack testing using either Method 8 or a modified Method 6 is unreasonable in terms of frequency and is inequitable to refiners using various control options. In addition, the commenter remarked that no data have been presented to support a thesis that emissions would vary so widely as to necessitate monitoring on a daily basis.

Another commenter (IV-K-5) opposed the proposed daily manual testing using Method 8 for FCCU's using sulfur reduction catalysts. The commenter provided three reasons as the basis for his remarks: (1) the approach is too labor-intensive; (2) EPA has not adequately demonstrated the need for this requirement; and (3) the requirement runs counter to the current national effort to increase the productivity of the American workforce.

Response:

These standards require an owner or operator to determine compliance status on a daily basis. For owners or operators using SO_x reduction catalysts to meet the standards, the Agency has thoughtfully and thoroughly considered options by which daily compliance determinations could be made accurately and with certainty. At this time, daily testing is the only method that the Agency knows will accomplish this goal. The Agency has "minimized" the amount of required sampling to one 3-hour test per day to help reduce the labor burden, but still meet the goal of daily compliance determinations. Thus, the Agency strongly disagrees that the frequency of the testing is either unreasonable or inequitable, as owners or operators subject to the standard for add-on controls or for low-sulfur content feeds are also required to make daily determinations. Data has been submitted by industry (for example, see Docket A-79-09, item IV-K-8) that show wide variation in SO_x emissions from FCCU's using SO_x reduction catalysts. Even if this variation does not vary "so widely," an FCCU operating right at the emission limit may go above the emission limit due to a small variation. Thus, daily compliance determinations are appropriate. The Agency points out that as additional data on FCCU's using SO_x reduction catalysts are generated, alternatives to Method 8 testing may become available and be used upon Administrator approval, but the daily determination of compliance is unlikely to change. That the approach is labor-intensive is irrelevant. The Agency has considered the cost of the daily testing and has determined the cost to be reasonable. Failure to make daily compliance determinations runs counter to the national effort for ensuring a cleaner environment. Thus, the Agency can see no merit to the comment that such testing and employment of labor to perform the testing runs counter to the national effort to increase the productivity of the American work force.

Comment:

One commenter (IV-K-6) believed that insufficient qualified contractor manpower exists to conduct the Method 8 compliance sampling.

Response:

The EPA assumed that in-house personnel would be used to conduct the Method 8 compliance sampling. The EPA believes there is sufficient lead time to train such personnel without requiring or solely relying on contractor manpower.

Comment:

One commenter (IV-D-16) stated that the proposed regulation does not supply sufficient information (calculation procedures) under Section 60.106, "Test Methods and Procedures," to determine total SO_x emissions.

Response:

The EPA agrees with the commenter. Therefore, the regulation has been revised to indicate that modification to the calculation procedures specified in Reference Method 8 will be required to calculate total SO_x emissions as SO_2.

Comment:

One commenter (IV-D-16) asked how SO_3 values could be presented in Table C-14 of the proposal BID when Section D.1.3.2 (page D-8) of the proposal BID states, in reference to the field tests providing the data for the values in Table C-14, "SO_3 could not be determined in the field ... ."

Response:

The remaining portion of the statement made in Section D.1.3.2 of the proposal BID states that SO_3 and particulate sulfate samples were later analyzed in a laboratory by ion chromatographic analysis. The emission summaries in Table C-14 of the proposal BID labeled "Sulfur Trioxide" included all sulfates collected in the isopropanol impinger which passed through a heated (178°C) filter. This would have included most of the sulfuric acid mist, if any were present (see next comment). The emissions labeled "Sulfates" included all water soluble sulfates collected in the probe and heated filter, as determined by water leaching the probe wash residue and filter and analysis of the leachate.

Comment:

One commenter (IV-D-16) asked if separate values for sulfuric acid mist and sulfur trioxide can be determined.

Response:

The EPA knows of no practicable technique to determine separate values for these two species.

Comment:

Many commenters (IV-K-1, IV-K-3, IV-K-4, IV-K-5, IV-K-8, IV-K-10, and IV-K-12) suggested alternatives to daily Method 8 testing for demonstrating continuous compliance. The commenters suggested three basic types of alternatives: (1) the use of less frequent Method 8 testing, (2) periodic testing for SO_x until an SO_3 CEMS is developed, and (3) the use of continuous SO_2 monitors with periodic testing for SO_3. One commenter (IV-K-8) stated, in general, that the daily application of Method 8 is cumbersome, and thus, the proposed rule should contain provisions to allow the permittee to demonstrate continuous compliance based on a broader spectrum of options. This commenter pointed out that: (1) the proposed rule restricts testing options and does not provide for flexibility with regard to future improvements in monitoring or operating strategy; (2) more flexible language would encourage better process understanding within the regulated community; and (3) exclusion of such a provision would require that future changes be made through formal rulemaking.

Less Frequent Method 8 Testing. One commenter (IV-K-10) stated that testing for continuous compliance may not need to be performed as frequently as proposed. This commenter suggested, for example, that if a week of daily Method 8 testing shows that no test is over the emission limit, then the testing frequency should be relaxed to seven tests on consecutive days once each quarter or semi-annually. The commenter pointed out that the tests are too expensive to be performed more frequently than necessary and that a history of testing data may show that daily testing by Method 8 is not necessary if there are no feed or operational upsets.

Periodic SO_x Testing Until SO_x CEMS Developed. Two commenters (IV-K-4 and IV-K-5) suggested that instead of daily Method 8 testing EPA require annual stack testing (IV-K-5) or quarterly or monthly stack testing as determined on a case-by-case basis (IV-K-4) until a SO_x CEMS has been developed. Commenter IV-K-5 suggested (as a second choice recommendation to annual testing) that EPA specify a continuous SO_x monitor and develop performance standards for such a monitor. This commenter provided literature on an SO_2 monitor that they thought should be able to monitor SO_3 also. The other commenter (IV-K-4) felt less frequent compliance testing was sufficient because their general experience with FCCU catalysts indicates that changes in emission rates from an FCCU that can achieve the proposed standards are sufficiently gradual to allow the less frequent compliance testing. Another commenter (IV-K-1) simply stated that some alternative to the SO_x standard should be used until a SO_x CEMS is proven to be practical in FCCU service.

SO_2 Monitors with Periodic Method 8 Testing. One commenter (IV-K-3) suggested using an SO_2 CEMS with an "SO_3 multiplier" to determine daily compliance, with the multiplier determined from a rolling average of periodic (e.g., biannual) measurements using Method 8. This commenter stated that the periodic tests could be run at representative feedstock and operating conditions to ensure a fair estimate of the SO_3 multiplier.

Another commenter (IV-K-12) recommended, if daily compliance determinations are required, the use of an SO_2 CEMS in conjunction with periodic comparisons of performance between the CEMS and Method 8. This commenter made this suggestion on the basis of: (1) their belief that SO_3/SO_2 ratios are relatively constant and predictable, and that the SO_3 component of SO_x is relatively insignificant; (2) EPA's data that describe the variability in the ratio of SO_3 to SO_x in emissions, and on which the requirement for daily testing is based, are limited and scattered; (3) maximum SO_3 emissions are most likely to occur when the FCCU regenerator is operated in a complete combustion mode without SO_x reduction additive on the catalyst, because, as the oxygen atmosphere increases, the conversion of SO_2 to SO_3 is favored, and SO_3 will be driven to maximum concentrations if SO_x reduction additive is not used to remove total sulfur; (4) a summary provided by them of emission monitoring at one of their FCCU's operating in the complete combustion mode without sulfur reduction additive shows reasonably good agreement between the CEMS and a wet chemistry method, and shows an SO_3 concentration of only a few parts per million -- less than 1 percent of total SO_x emissions; and (5) additional FCCU test results provided by them support their conclusion that regenerator flue gases on units not using SO_x reduction catalysts but with CO boilers contain negligible amounts of SO_3.

A third commenter (IV-K-8) proposed that the fraction of SO_3 not recorded on the SO_2 monitor be determined periodically by a Method 8 or modified Method 6. This would be in addition to SO_2 monitoring on a continuous basis. This commenter pointed out that data provided by them indicates that approximately 10 to 20 percent of the flue gas sulfur occurs as SO_3.

Response:

The Agency has considered the alternatives suggested by the commenters. The Agency agrees that any test should not be performed more frequently than necessary and that a history of test data may show that daily testing is unnecessary. However, such a "history of test data" does not exist at this time and without such data, the Agency does not believe any of the alternative monitoring or testing schemes suggested can be implemented at this time and ensure that accurate continuous compliance determinations are made. Further, the commenters did not provide much data to support their arguments, and available data show that the SO_3/SO_x ratio can be variable.

As noted above, one of the commenters provided literature on an SO_2 monitor that they thought should be able to monitor SO_3 also. The information and literature provided were insufficient for the Agency to evaluate this potential for this particular monitor. The Agency has examined other monitors for their ability to monitor SO_x. To date, none of the monitors examined has proven suitable.

The Agency does agree that many of these alternatives may be shown acceptable as more data on SO_x reduction catalyst use and SO_x emissions are generated. Therefore, the standard explicitly states that such alternatives supported by sufficient data may be approved on a case-by-case basis. Some of the criteria that may be considered are the SO_3/SO_x ratio, product feed variability, frequency of product slate changes, operational variability in regenerator conditions (e.g., excess oxygen, temperature), catalyst addition schedules, and FCCU operating conditions. The development of a successful SO_x monitor would also be an acceptable alternative, upon approval by the Administrator, to Method 8 testing. In the meantime, however, the Agency has retained daily Method 8 testing for determining compliance on a continuous basis for the FCCU without add-on control standard.

Comment:

One commenter (IV-K-6) states that the use of continuous SO_2 monitors will provide a means of determining compliance for FCCU's without add-on controls at a more reasonable cost than Method 8.

Response:

As discussed in Section 2.2, "Regulated Pollutant," the Agency continues to believe that SO_x is the most appropriate regulated pollutant for FCCU's operating without add-on controls. As SO_2 monitors do not measure SO_3, they cannot be used to provide continuous compliance determinations when SO_x reduction catalysts are being used.

Comment:

Two commenters (IV-D-6 and IV-D-9) stated that the continuous emission monitoring requirement should be eliminated for the standard for FCCU's without add-on controls because FCCU outlet SO_2 concentrations are not a true indication of the SO_x emission rate. The commenters argued that variables in subsequent operations can differ considerably from those during the performance test, making outlet concentrations unsuitable as a gauge of compliance.

Response:

As originally proposed, EPA considered SO_2 monitoring as the most reasonable means of determining excess emissions for FCCU's using SO_x reduction catalysts, recognizing that such an excess emission level based on FCCU outlet SO_2 concentration does not provide a precise indication of SO_x emissions per 1,000 kg of coke burn-off. This particular concern, however, is no longer relevant as the standard now requires daily determination of compliance using direct measurements of SO_x emissions (i.e., daily testing with Method 8).

Comment:

One commenter (IV-D-16) stated that since there will be catalyst particles in the flue gas to the scrubber, how can Method 8 be used as Method 8 requires "the absence of other particulate matter?" The commenter also pointed out that this problem could render Method 8 invalid for outlet gases. This commenter also asked in a later comment letter (IV-K-2) how EPA knows that the revised proposed Method 8 is not subject to interference from particulates as is Method 8. In addition, the commenter questioned whether testing of revised proposed Method 8 has been performed that shows no particulate interference, repeatability by one tester, reproducibility by different testers, precision, and accuracy.

One commenter (IV-K-4) stated that EPA has failed to recognize possible interfering effects associated with common practice for particulate control in the Method 8 stack test measurement. The commenter believes that refiners are likely to use an ESP to comply with the FCCU particulate standard. The commenter stated that, according to EPA, the injection of either ammonia or an "enhanced" amine into the ESP to adjust particle resistivity and improve fine particle removal in the ESP can produce significant interfering effects in SO_x determinations using Methods 6 and 8. The commenter added that more developmental work should be done to identify and quantify these interfering effects on the SO_x emission test methodology before EPA adopts a specific test method for NSPS SO_x compliance monitoring purposes.

Response:

The EPA agrees that the presence of "other particulate matter" could invalidate the Method 8 test results. Therefore, appropriate changes have been made in the regulation to permit the insertion of a heated filter and probe in the sampling train, prior to the impingers. The heated probe and filter will prevent the particulate matter from getting into the impinger solution. Filters would be required that are at least 99.95 percent efficient, as required in Section 3.1.1 of Method 5. There is no indication or reason to suspect these filters would not eliminate the analysis problem. If analytical interference because of particulates still exist, then alternative analytical techniques (for example, ion chromatography) are available for use upon approval by the Administrator.

The Agency has not conducted testing of Method 8 as modified under these standards to specifically address the commenter's concerns. The Agency knows of no technical reason, however, as to why the modifications to Method 8 under this subpart would adversely affect the repeatability, reproducibility, precision, or accuracy of Method 8. In addition, EPA is currently developing test procedures for minimizing the sulfate interference in particulate matter measurements. The alternative of measuring both particulate matter and sulfur oxides with the same equipment and analytical techniques will be addressed at that time.

The EPA acknowledges that ammonia has known interfering effects on SO_x determinations. We believe there are alternative techniques to eliminate the interference and are currently studying potential interference problems with respect to ammonia. Thus, in cases where ammonia and/or amines are expected or are known to create problems, the owner or operator should consult the Administrator for approval of alternative test methods.

Comment:

One commenter (IV-K-6) stated that the collection of a grab sample using Reference Method 8 is less reliable than a continuous on-line analyzer, even though there could be some minor variation in the SO_3 to SO_2 ratio in the stack gas. The commenter believed the use of Method 8 could give unrealistic results where an unscrupulous operator could adjust the operating conditions prior to obtaining the daily sample.

Response:

The revised proposed standards specified that the measurement of SO_x emissions from FCCU's using SO_x reduction catalysts would be accomplished by conducting revised Method 8 for one shift each day. The Agency knows of no evidence that the variation in total SO_x through the course of a day is any greater than the variation in the SO_2 to SO_3 ratio in the stack gas and thus no evidence for the commenter's remarks.

The EPA assumes that operators will obtain valid samples that are representative of operating conditions at the facility and, therefore, will not alter operating conditions prior to sampling. Such deliberate actions on the part of an owner or operator to obtain unrealistic results clearly constitute a circumvention of the standard and is illegal under Subpart A, the General Provisions (40 CFR Section 60.12). Inspection of plant operating data by EPA and State personnel would lead to detection of such alteration of plant operation.

Comment:

One commenter (IV-K-2) questioned whether 160°C (320°F) is the appropriate temperature for the heated probe and filter in the revised Method 8. The commenter based his question on the following assertions:

(a) The commenter believed that the dew point for SO_3 can often be above this value, especially for FCCU's running more than

0.3 weight percent sulfur in the feed, and collecting sulfuric acid in the heated filter will not help the revised Method 8 to yield correct results.

(b) The commenter believed that a minimum probe temperature of 200°C (400°F) was being established for Method 5, and believed the 160°C probe temperature seems to be recreating an earlier problem.

(c) The commenter believed that this modification would allow the probe and heated filter to corrode and leak in a few days if used in a flue gas with a high SO_x content.

This commenter also asked how the 160°C (320°F) temperature at the probe is reached if the stack temperature is hotter, or if it is colder. This commenter stated that if a "probe catch" is a deposit in the probe, the probe would soon plug up.

Response:

The EPA based the selection of the temperature for the heated filter and probe in the revised Method 8 on the temperature specified in the proposed Method 5B and 5F (50 FR 21863, May 29, 1985), which are the methods for sampling particulate matter at FCCU's. The EPA agrees that the dew point for SO_3 may be higher than the temperature of the heated filter and probe (160°C). In such instances, the filter would pick up condensed SO_3 (most likely, though, as sulfuric acid mist), thereby leading to a low estimate of SO_3 as measured in the impingers. The Agency believes that this problem is small because the filter would pick up only a small part of the sulfuric acid mist, and the rest would pass through the filter and be collected in the impingers. Thus, the Agency recognizes that, in such situations, a potential bias exists to underestimate emissions, but believes that it is small provided the 160°C is maintained.

The commenter's third assertion is neither relevant nor correct. The materials used (glass and stainless steel) in the probes and filter holders are not subject to corrosion from sulfuric acid. Further, the probes and filter holder are removed each day (after the 3-hour test) for cleaning. In addition, FCCU operators would be required to conduct periodic leak checks. If leaks are detected in the system, or if the sampling system fails, then the system would need to be repaired.

With regard to the stack temperature being different from the probe temperature, if the stack temperature is hotter, there is no problem from an SO_x enforcement standpoint - more SO_x will be trapped in the impingers - and thus no temperature adjustment has to be made at the probe. However, if the stack temperature is colder, less SO_x will pass through the filter and a temperature adjustment has to be made. It is common practice to electrically heat the probe to attain the desired temperature.

Finally, with regard to plugging of the probe, as part of normal operating procedures, sampling conducted using revised Method 8 requires that the probe be cleaned out after each run and that the collected sample be discarded from the analysis. This procedure eliminates the potential problem brought up by the commenter.

Comment:

One commenter (IV-K-2) asked why the isopropanol impinger was deleted from Method 8.

Response:

Method 8 was designed primarily for the separate capture and measurement of sulfuric acid and SO_2. The isopropanol (IPA) impinger is used to collect sulfuric acid and SO_3, while the hydrogen peroxide impinger is used to collect SO_2. In the absence of the IPA impinger, the hydrogen peroxide impinger will collect all the SO_x compounds together. The current standards for SO_x reduction catalysts are based on total SO_x; there is no need to separate SO_2 from other sulfur emissions. Therefore, EPA eliminated the IPA impinger from Method 8, the effect of which is to simplify the test procedure, analysis, and calculations.

6.4 FEED SULFUR CUTOFF

Comment:

One commenter (IV-K-10) felt that the cost of testing the feed sulfur at FCCU's using the alternative feed sulfur cut-off standard is too expensive to be performed more often than is necessary and suggested that such testing should be required once per week if the feed is previously found to contain below 0.3 percent sulfur in every sample for a week.

Response:

For these standards, owners and operators are required to determine compliance on a continuous basis (i.e., on a daily basis). As described in the proposed standards, most refiners manually sample the FCCU fresh feed once per day. Fresh feed sulfur content, however, may change on an hourly basis. Requiring samples to be collected once per hour is not practical using manual sampling techniques. Therefore, the Agency selected a sampling frequency of one sample per 8-hour shift. This frequency would measure major fluctuations in fresh feed sulfur level and is reasonable considering current refinery sampling practices. The sampling program suggested by the commenter would not allow the Agency to be sure that the owner or operator is in fact meeting the standard on a daily basis. Furthermore, past feed usage is not a good indicator of future use; many refiners use different feeds or feed blends for short periods of time. Therefore, the Agency has retained daily testing for feed sulfur content for those operators using this alternative standard.

7.0 COMPLIANCE COMMENTS

7.1 SOURCE OPERATION DURING MALFUNCTIONS

Comment:

One commenter (IV-D-7) requested that EPA consider establishing standards that allow a certain amount of scrubber downtime without requiring a FCCU shutdown.

Response:

The General Provisions in 40 CFR 60 provide for malfunction of control equipment. "Malfunction" means only sudden and unavoidable failure of air pollution control equipment, process equipment, or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition, are not considered malfunctions. As stated in Section 60.8(c), emissions in excess of a standard due to a malfunction do not represent a violation of the standard. In addition, scrubbers currently applied to FCCU's have demonstrated reliability levels in excess of 95 percent (discussed in Section 3.1 of this document). Thus, it is unnecessary to provide a provision in the standards for scrubber downtime.

Comment:

One commenter (IV-D-16) asked if the affected facility is allowed to continue operating during continuous emission monitor malfunctions.

Response:

An affected facility may continue to operate during continuous emission monitor malfunctions. However, as prescribed under 40 CFR 60.7(b) and (c)(3) of the General Provisions, the owner or operator shall maintain records of any periods during which a continuous monitoring system or monitoring device is inoperative, and the quarterly (or semiannual, if no exceedances have occurred during a particular quarter) compliance report shall include the date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of the system repairs or adjustments. It should be noted that failure to properly operate or maintain a continuous monitoring system would be considered as a violation rather than a malfunction (see 40 CFR 60.105 and 60.13).

7.2 COMPLIANCE USING PARTIAL SCRUBBING

Comment:

One commenter (IV-D-3) stated that EPA should delete the requirement that the add-on control device must be operated to reduce SO_x in the entire exhaust stream by 90 percent (or to 50 vppm). Instead, a portion of the FCCU regenerator exhaust gas could bypass the scrubber and rejoin with the scrubbed portion further downstream. A refiner could then operate a smaller scrubber at or less than full capacity to meet the 9.8 kg SO_x/1,000 kg coke burn-off level of the standard for FCCU's without add-on controls. A smaller scrubber would mean smaller capital and annual operating costs, energy savings, eliminate the need for reheat, and improve nonair environmental benefits.

Response:

The 90 percent standard is intended to reflect the capability of scrubbers, which can achieve 90 percent control of the entire exhaust stream. A relaxation of the standard to 9.8 kg SO_x/1,000 kg coke burn-off would cause it no longer to reflect the capability of scrubbers.

7.3 CHANGING COMPLIANCE METHOD

Comment:

A commenter (IV-D-16) questioned the need for a compliance test after each change by a refiner from one method of compliance to another. Rather, the commenter stated that one compliance test for each compliance method the first time selected is sufficient.

Response:

This comment is no longer applicable as the standards now require daily determinations of compliance. Under the standards, a compliance test (by definition) is required every day regardless of the standard with which the owner or operator seeks to comply or to which the owner or operator has been previously subject.

Comment:

Four commenters (IV-D-2, IV-D-6, IV-D-16, and IV-D-20) wrote that the 90-day notification prior to changing from one method of compliance to another should be modified to allow for an immediate change in emergency cases. The commenters pointed out example situations, such as an emergency shutdown of a hydrotreater or of a scrubber. According to the commenters, in such cases a refiner would want to comply with a different standard (e.g., change from the standard for FCCU's without add-on controls to the feed sulfur cutoff) immediately, rather than curtail FCCU processing until the shut-down control unit is repaired.

Two of these commenters (IV-D-6 and IV-D-20) stated that no prior notification should be required provided that records appropriate to demonstrate compliance are maintained, and EPA is notified in writing of the change in compliance method.

Response:

The regulation now requires that daily compliance determinations be made for all of the standards. Thus, EPA agrees with the commenters and has removed the requirements for prior notification provided that records appropriate to demonstrate compliance with the regulation are maintained, and EPA is notified in writing of the change. However, prior notification is required whenever an owner or operator adds any CEMS (e.g., when an owner or operator elects to go from the 50 vppm only compliance to 90 percent reduction or 50 vppm compliance). Notification is also required in a quarterly report of any change in the choice of SO_x standard with which an owner or operator elects to comply. The notification of any other changes in the standard to which a refiner is subject may be submitted along with a quarterly (or semi-annual) compliance report.

8.0 MODIFICATION/RECONSTRUCTION COMMENTS

Comment:

One commenter (IV-D-2) suggested that the definition of reconstruction, as written in 60.108(a), should be modified to exclude equipment which is replaced by equipment alike in design, shape, and metallurgy. The commenter cited an example of an existing unit damaged by disaster or misfortune.

Response:

Section 60.15 of the General Provisions specifies that reconstruction occurs upon replacement of components if the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable, entirely new facility and if it is technologically and economically feasible for the facility, after the replacements, to comply with the applicable standards of performance. The circumstances prompting the reconstruction activities are not pertinent when determining if an existing facility has undergone reconstruction.

Each reconstruction determination is decided on a case-by-case basis. Section 60.15(f) sets forth the criteria which the Administrator will use in making his determination. If the owner/operator of the facility can provide evidence that it is not technologically or economically feasible to comply with the applicable standards, the facility will retain its "existing" status. However, if the fixed capital cost provision is met and it is feasible for the facility to comply with the standards, it must comply with NSPS.

Comment:

One commenter (IV-D-3) stated that a special provision should be included in these standards to supercede Section 60.14 regarding the definition of modification. Specifically, the commenter referred to the determination of whether a given "project" will increase SO_x emissions from an existing FCCU regenerator that is using SO_x reduction catalysts. The commenter recommended that, in determining whether an emission increase will result, operators should be allowed to use, for the pre-project case, the emission level which would have existed had SO_x reduction catalysts not been used. A modification would not occur unless the post-project emissions exceeded this adjusted pre-project level. Operators who do not use SO_x reduction catalysts would have an advantage over those who do in preventing an emission increase in a given "project." They can use SO_x reduction catalysts concurrently with the project and thereby avoid a net emission increase at the affected facility.

Response:

The inclusion of the suggested special provision is inconsistent with Section 111(a)(4) of the Clean Air Act, which defines "modification" to mean "any physical change in, or change in the method of operation of" a source that increases emissions. It is also contrary to the intent of the modification provision and the NSPS program. The EPA believes that the current straightforward application of the "modification" definition best serves the intent of Section 111 of the Clean Air Act. One key purpose of the NSPS program is to prevent new pollution problems. One way that the statute seeks to achieve this is by requiring compliance with NSPS at, and thereby minimizing emissions increases from, modified facilities.

Comment:

One commenter (IV-D-7) stated that routine maintenance items, such as standpipes, slide valves, and other regenerator internal components should not be included in determining if a facility is modified or reconstructed. Many of the items require routine maintenance and are frequently repaired without a resultant emissions increase. Another commenter (IV-D-16) stated that the affected facility should be redefined to include the fractionator and gas plant because rebuilding work in a single turnaround of an affected facility can commonly exceed 50 percent of the cost of a new unit. Also, the cost of rebuilding work on an affected facility can represent 20 percent of the new unit cost of an entire FCCU. To a refiner, an entire FCCU includes the fractionator and gas plant. These two units usually do not require any significant rebuilding.

Response:

The reconstruction provision (40 CFR 60.15) cannot be invoked until 50 percent of the "fixed capital cost" to replace the existing facility with a comparable, new facility has been incurred by the owner or operator. The period in which the FCCU is shut down for maintenance and repair is called a turnaround. During a typical turnaround, regenerator refractory linings, cyclones, and other internal components are inspected and repaired or replaced as required. Based on information from the refining industry, regenerator components have a useful life ranging from 10 years to an indefinite period of time when they are repaired and maintained during turnarounds (see Docket A-79-09, items II-D-40, II-D-41, II-D-42, and II-D-43). The costs used in the summation to determine the total fixed capital cost incurred are those costs incurred to replace components. The costs incurred during maintenance and repair of the existing facility's components (assuming components are not replaced) are not included in the summation of expended fixed capital costs. Thus, there is no need to specifically exempt routine maintenance items from the reconstruction provisions.

The EPA disagrees with the comment that rebuilding work typically can exceed 50 percent of the capital cost of a new affected facility. The EPA examined data from Section 114 letter responses, trip reports, literature articles, and companies who provide turnaround services to refineries (see Docket A-79-09, item IV-B-18). These data led EPA to conclude that routine rebuilding is less than 50 percent of the cost of a new affected facility. As discussed above, this is because regenerator components are typically repaired rather than replaced during a turnaround. If several major changes, such as increasing the FCCU capacity, changing to a heavier or more sour crude oil, or converting to high-temperature regeneration, occur during a single turnaround, the cost may approach or surpass the 50 percent point. Such major changes are not, however, a typical turnaround occurrence. Justification for the choice of equipment that comprises the affected facility, as defined in 40 CFR 60.101(n), is discussed in Section 2.2 of this document. The possibility that rebuilding work may exceed 50 percent of the cost of a new unit is an inadequate reason to broaden the definition of the affected facility (i.e., restrict invoking the reconstruction provision). The meaning and intent of the reconstruction provision is discussed earlier in this section.

The modification provision (40 CFR 60.14) is invoked when any physical or operational change to an existing facility results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies. As the actions described by the commenter do not increase emissions, the modification provision would not be invoked. In addition, paragraph (e) of Section 60.14 specifies that routine maintenance, repair, and replacement by themselves, shall not be considered modifications.

Comment:

One commenter (IV-D-8) stated that a 1-calendar year or a 12-month "inclusion period" for reconstruction is more logical than a 2-year period. A refiner with a normal 2-year turnaround could be affected by the reconstruction provisions of the standards if a shutdown began 1 or 2 months prematurely. A refiner would not install a sizeable process modification during a routine shutdown period due to the excessive downtime incurred.

Response:

The EPA considered again the 2-year period and concluded that a 1-calendar year or a 12-month "inclusion period" for reconstruction is not more logical than a 2-year period for FCCU's. Information from industry and literature (see proposal BID, p. 5-3) indicates that the normal turnaround schedule for revamping FCCU regenerators is every 3 years (i.e., a maximum of one turnaround would occur during each 2-year period of operation). A process unit turnaround typically includes maintenance and repair items that do not qualify as fixed capital costs and therefore, a turnaround is not likely to be a "reconstruction." The Agency also does not expect that the 2-year period will alter decisions by an FCCU's owner or operator on when to replace equipment. That is, the FCCU owner or operator is not likely to unduly prolong the useful life of the regenerator components with the intent of avoiding this NSPS. Therefore, for this particular NSPS, EPA believes that the 2-year period provides a reasonable, objective method of determining whether an owner/operator of an FCCU regenerator is actually "proposing" extensive component replacement, within the original intent of Section 60.15. The Agency will consider the 2-year period again at the 4-year review of the NSPS.

Comment:

One commenter (IV-D-13) questioned the methods to be used in determining if an emissions increase has occurred when determining the applicability of the modification provisions. The commenter stated that EPA should outline the specific information acceptable for an emission factor and/or material balance approach. The commenter also asked what specific AP-42 or other emission factor for FCCU's EPA intends to use. Another commenter (IV-D-15) suggested taking into consideration whether the tonnage of a coke burnoff is increased by substantial amounts.

Response:

Specific guidelines cannot be presented to be used to determine whether an increase in emissions has occurred due to the wide variability of possible circumstances. One factor that undoubtedly would be considered in assessing whether an emission increase had occurred or would occur is whether the facility is or will be capable of utilizing a new feedstock. A new feedstock will probably have a different sulfur content than those previously used, and thus, there is a strong possibility that the SO_x emissions will change. If the existing facility was designed to accommodate the alternative raw material, however, then an increase in emissions resulting from that change alone is not considered a modification [see 40 CFR §60.14(e)(4)]. Another factor that would be considered is whether the facility is or will be capable of increased coke burn-off. Assuming no change in the feedstock, an increase in the coke burn-off rate will undoubtedly cause SO_x emissions to increase because the amount of SO_x emissions is directly related to the amount of coke that is burned off.

Pollutant emission rates can be estimated for FCCU regenerators by using emission factors described in AP-42; however, these emission factors generally represent average emission levels and thus do not reflect the complete range of emissions from individual FCCU regenerators. The range of FCCU regenerator pollutant emission rates may be determined by considering the typical ranges in feed sulfur, coke yield, and FCCU capacity, and by evaluating the stoichiometric relationships involved in regenerating FCCU catalysts.

Catalyst regeneration is similar to solid fuel combustion in a boiler. Flue gas compositions and flow rates may be calculated by determining the coke composition and formation rate and by calculating the amount of air required to oxidize the coke. Coke formation rates vary depending on the FCCU and how it is operated. Coke yield, expressed as a weight percentage of the feed, varies between 4 weight percent and 6.5 weight percent for many FCCU feeds (see Docket A-79-09, item II-I-53).

Coke is composed of carbon, hydrogen, sulfur, and small amounts of nitrogen and metals. Coke may typically contain from 4 to 12 percent hydrogen (see Docket A-79-09, items II-D-50, II-D-49, and II-D-47). The sulfur content of the coke may range from less than 0.1 to 5 weight percent or more, depending on the type of feed processed. Assuming that the nitrogen and metals content of coke is negligible, carbon would represent the balance of coke composition.

Certain regenerator combustion air inlet and flue gas compositions must also be assumed when calculating emissions. Inlet air to the regenerator may contain from 76.0 to 78.8 volume percent nitrogen, 20 volume percent oxygen, and from 1.2 to 4.0 volume percent water. A detailed discussion describing calculation and/or estimating techniques to determine emission rates is presented in the proposal BID, pp. 3-15 and 3-16.

Comment:

One commenter (IV-D-16) recommended that Section 60.100(b) and (c) should be rewritten, to allow a better understanding of reconstruction.

Response:

Sections 60.100 (b) and (c) are not intended to provide the definition or clarification of the definition of reconstruction, as it applies to 40 CFR 60; however, Section 60.100(c) was confusing and it has been revised. A detailed discussion of the meaning of reconstruction is provided in Subpart A, General Provisions, under Section 60.15. Specific clarifications or additions to the definition of reconstruction, as applicable for Subpart J, are provided under Section 60.108.

9.0 RECORDKEEPING AND REPORTING COMMENTS

Comment:

The Office of Management and Budget commented that quarterly reporting was too frequent, and that semiannual reporting would allow the Agency to obtain the necessary information.

Response:

For FCCU's, EPA has concluded that quarterly reporting (or semiannual reporting if no exceedances have occurred during a particular quarter) is the appropriate reporting frequency for the following reasons. The major reason is that the reports contain direct compliance information rather than indicators of the source's performance. Therefore, enforcement action can be taken quickly because no further testing is needed for documentation. The FCCU is one of several significant emission sources in petroleum refineries, so periods of excess emissions could have a significant impact on the environment. This is particularly true because refineries generally are located in clusters near industrial, urban, populated, nonattainment areas. Because the refinery generally does not save money by operating the control techniques correctly and the pollutants cannot be recovered for resale, there is little incentive for this source category to be self-regulated. Therefore, to ensure that sources are not out of compliance for long periods of time during which significant environmental impacts could occur, quarterly reporting is appropriate for quarters when facilities have had a period when the standard has been exceeded. In addition, the amount of data to be provided in these cases is reasonable. Sources complying with the proposed revised standard would need to supply only a semiannual negative declaration statement. Only noncompliant sources would be required to provide additional information in the quarterly compliance reports.

10.0 MISCELLANEOUS COMMENTS

Comment:

One commenter (IV-D-16) wrote that since the proposal preamble states that FCCU flue gas is similar to stationary source flue gas, the SO_x rules that apply to stationary sources should be prescribed for FCCU's. If these rules were applied to FCCU's, regenerators with heat releases less than 250 million BTU's per hour would be exempt.

Response:

The EPA assumes that by stationary sources, the commenter is referring to utility boilers. Although the composition of the flue gas from a coal-fired utility boiler is similar to that of FCCU regenerator exhaust gases, and some of the same control devices are applicable, it is not appropriate simply to copy the standards for utility boilers to FCCU's when significant differences could exist between the two source categories. Whenever practical, the process operation and economic aspects that characterize the source category or industry for which standards are being developed should be considered. In addition, the SO_x standards for FCCU's consider the additional control alternatives available to FCCU's that are not available to utility boilers. The utility boiler standard applied to FCCU's would reduce a refiner's flexibility to use high sulfur feedstocks and would not allow the use of SO_x reduction catalysts, low sulfur feedstocks, or hydrotreating. Thus, it is not reasonable to simply copy the SO_2 standards for utility boilers.

Comment:

Two commenters (IV-D-6 and IV-D-10) suggested that the proposal package should undergo NAPCTAC review again because at the original NAPCTAC meeting the regulation was in terms of SO_2 while the current proposed standards are in terms of SO_x.

Response:

The purpose for a NAPCTAC meeting is for EPA to receive comments from an independent advisory committee regarding the need for standards, regulatory alternatives, control techniques, control costs, and other factors. Although the standard for FCCU's without add-on controls is in terms of SO_x, the standard is still achievable by the identified control techniques and the environmental, energy, and economic impacts are still reasonable. Therefore, it is not necessary to conduct another NAPCTAC review due to the change of this standard from SO_2 to SO_x.

Comment:

One commenter (IV-K-2) asked why EPA requires dates and explanations when fewer than 18 valid hours of continuous emissions monitoring data have been obtained.

Response:

Facilities using add-on controls are required to obtain 18 or more valid hours of CEMS data for at least 22 days each month. As pointed out by this same commenter elsewhere, there is some possibility than an owner or operator may try to maximize the "good" days and minimize the "bad" days in trying to meet the standard. Such deliberate actions are attempts to circumvent the standard, which is illegal under 40 CFR Part 60, Subpart A, Section 60.12. In other words, such an owner or operator may turn off the CEMS or otherwise invalidate its data on a "bad" day in order to generate less than 18 valid hours. With the dates and a brief explanation, the Agency can look for patterns that indicate that an owner or operator may be circumventing the standard and thus discourage this type of behavior.

Comment:

One commenter (IV-K-2) suggested that EPA should not use "monitored parameter data," but use "excess emissions" to target inspections.

Response:

The discussion of "Monitored Parameter Data" and "Excess Emissions Data" in the reproposal notice was generic to the entire NSPS/NESHAP development process and not addressed specifically to the FCCU standards being proposed. While both types of data may not be needed to target inspections for any one standard, in some cases, monitored parameter data may be more appropriate to collect than excess emission data. For example, in standards that require particular equipment rather than being a numerical emission limit, monitoring operating parameters would likely be the best data to collect for targeting inspections. Thus, the Agency will continue to judge, on a case-by-case basis, the type of data that is appropriate for each NSPS or NESHAP.

Comment:

One commenter (IV-K-2) asked what is the difference between a "redundant" CEMS and a "spare" CEMS. The commenter pointed out that EPA states that redundant CEMS's are not warranted because of cost, but later discusses the use of a spare CEMS.

Response:

If EPA required a CEMS to operate close to 100 percent of the time, then a second CEMS would be required to ensure that high percent availability. It is in this context that EPA refers to the second monitor as a "redundant" CEMS and believes that the cost for ensuring close to 100 percent availability is not warranted. Thus, EPA proposed minimum data requirements that could likely be met by a single CEMS, taking into account downtime. Even still, there may be times when minimum data requirements are not met by the (first) CEMS. The owner or operator has at least three options in obtaining the needed data - Method 6 testing, Method 6B testing, or a second CEMS. It is in this context that EPA refers to the second CEMS as a "spare" monitor. Therefore, with the minimum data requirements and the manual testing options, a second CEMS is optional, but not required. The EPA recognizes that for an owner or operator who chooses to purchase a second CEMS for back-up purposes there is no meaningful difference between "redundant" and "spare."

Comment:

One commenter (IV-K-2) pointed out that the preamble example of 88 percent reduction as being an exceedance may not, in fact, be an exceedance if the SO_2 is less than 50 vppm.

Response:

The Agency agrees that the example provided in the preamble is incomplete. An add-on control device whose outlet SO_2 emissions are 50 vppm or less is not in exceedance of the standard regardless of the add-on control percent reduction. The example implicitly assumed that the outlet SO_2 vppm was greater than 50. The object of the example was primarily to point out that for percent reduction an exceedance would occur when the control device efficiency was less than 90 percent.

Comment:

One commenter (IV-K-2) suggested that EPA use the words "failure to achieve a standard" rather than "exceedance of a standard" to describe emissions greater than those allowed by a standard. The commenter added that "exceedance" has the connotation of being better than or superior to, which, in the case of a percent reduction standard, would be a reduction better than required.

Response:

The word "exceedance" is used by EPA in the context of not achieving a prescribed emission level set by EPA. Exceedance of a percent reduction standard means that a facility or process unit has not achieved an emission level (in this case, 90 percent emission reduction based on flue gas scrubbers) specified by EPA. This term has been used by EPA in numerous standards of performance. Therefore, to maintain consistency with other standards, the use of the word "exceedance" has been retained.

Comment:

One commenter (IV-K-2) asked whether the words "source owner" on page 46465, column 1, paragraph 1, of the preamble to the revised proposed standards should be "source owner or operator." This commenter also asked whether the word "provide" on page 46465, column 1, paragraph 1, of the preamble to the revised proposed standards means "report" or "record." In addition, the commenter pointed out various typographical errors in the preamble. In an earlier comment letter (IV-D-16), this commenter provided a thorough list of editorial and typographical changes that should be incorporated into the proposal BID and the Federal Register notice.

Response:

The EPA inadvertently omitted the words "or operator" from the sentence referred to by the commenter. Therefore, EPA wishes to clarify that the requirement to provide a minimum of 22 days of data for every 30-day period using continuous monitors or an approved manual emission test is the responsibility of either the plant owner or operator or an appropriate person designated by the owner or operator.

The commenter refers to the requirement to "provide" monitoring data for determining performance of the add-on control device (using continuous monitors or an approved manual emission test). As explained in the preamble to the revised proposed standards on page 46467 under "Recordkeeping and Reporting Requirements," refiners subject to the standard for FCCU's with add-on controls would be required to record the data from the continuous emission monitor at the inlet, as well as at the outlet. Therefore, the word "provide" means to "record" in the context of this requirement.

A listing of each typographical error and suggestion is not provided here since the errors and suggested changes do not affect the intent or technical discussions presented in these documents. None of the typographical errors impairs the meaning or explanation of the standards intended by EPA. The suggestions have been reviewed and all appropriate changes have been made.

APPENDIX A

CONTROL EQUIPMENT COSTS AND FIFTH YEAR IMPACTS

TABLE A-1. BASIS FOR DETERMINING SCRUBBER ANNUAL COSTS[a]

Direct Operating Costs	
Labor[b]	$17.51/hour
Maintenance (includes materials, labor, and overhead)	1.5 percent of total capital cost
Utilities	
Electricity	$0.0795/kWh
Water	$0.0763/m^3
Compressed Air	$0.861/1,000 m^3
Caustic Soda[c] (Soda Ash[d])	$268/Mg ($122/Mg)
Steam	$13.53/1,000 kg
Polyelectrolyte[e]	$10.07/kg
Solid Waste Disposal[f]	$20.13/Mg
Liquid Waste Disposal[f] (to sewer)	$0.16/m^3
Indirect Operating Costs	
Tax, Insurance, and Administration	4 percent of total capital cost
Capital Recovery Factor	13.15 percent of total capital cost

[a] Fourth quarter 1984 dollars.

[b] Includes 40 percent overhead; U.S. Department of Labor, Bureau of Labor Statistics.

[c] Liquid caustic soda, 100 percent; F.O.B. Gulf Coast; Docket A-79-09, item II-E-6

[d] Bulk soda ash, light, 99 percent; F.O.B. Wyoming; Docket A-79-09, item II-E-6.

[e] Polymer 3300, an anionic polyacrilomide settling agent; 50-pound bags, F.O.B. Dallas, Texas.

[f] From industrial boilers - EPA-450/3-82-021 August 1982. Costs of Sulfur Dioxide, Particulate Matter and Nitrogen Oxide Control on Fossil Fuel Fired Industrial Boilers. p. 2-16.

TABLE A-2. CAPITAL COST FOR SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING SYSTEM AND PURGE TREATMENT FOR MODEL UNITS[a]

Capital Costs	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
Direct Costs[b]	2.9	5.0
Indirect Costs	1.3	2.2
Contingency Costs[c]	0.8	1.4
TOTAL CAPITAL COST	5.0	8.6
ESP Capital Cost Credit[d]	-1.0	-1.8

[a] Costs are reported in millions of dollars, adjusted to fourth quarter 1984 dollars, delivered to a Gulf Coast location.

[b] Materials and labor.

[c] Twenty percent of total direct and indirect costs.

[d] From Table A-9 in this appendix; cost provided for comparison purposes.

TABLE A-3. ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR 2,500 m^3/sd MODEL UNITS

Annual Costs	Annual Cost, in Thousands of Dollars[a]		
	0.3 wt. % Sulfur Feed	1.5 wt. % Sulfur Feed	3.5 wt. % Sulfur Feed
Direct Operating Costs			
Labor	53.7	53.7	53.7
Maintenance	75.0	75.0	75.0
Utilities			
Electricity	22.4	22.4	22.4
Water	10.2	10.2	10.2
Compressed Air	0.4	0.4	0.4
Caustic Soda (Soda Ash)	155 (95)	579 (355)	1,089 (668)
Steam	1.1	1.1	1.1
Polyelectrolyte	4.9	4.9	4.9
Solid Waste Disposal	7.1	7.1	7.1
Liquid Waste Disposal[b]	15.6	15.6	15.6
Indirect Operating Costs			
Tax, Insurance, and Administration	200	200	200
Capital Recovery Cost	658	658	658
TOTAL ANNUAL COST			
Caustic Soda (Soda Ash)	1,200 (1,140)	1,630 (1,400)	2,140 (1,720)
ESP Credit[c]	-272	-272	-272
NET ANNUAL COST			
Caustic Soda (Soda Ash)	930 (870)	1,360 (1,130)	1,870 (1,440)
EMISSION REDUCTION [Mg SO_x removed/yr]	450	1,670	3,130
COST EFFECTIVENESS[d] [$/Mg SO_x removed]	2,070	810	600

[a] Numbers may not add to totals due to rounding. Fourth quarter 1984 dollars.

[b] Assumes liquid waste disposal to sewer, 50 gal/minute.

[c] From Table A-9 in this appendix.

[d] Based on net annual cost with caustic soda.

TABLE A-4. ANNUAL COST OF SODIUM-BASED HIGH ENERGY VENTURI SCRUBBING FOR 8,000 m^3/sd MODEL UNITS

Annual Costs	Annual Cost, in Thousands of Dollars[a]		
	0.3 wt. % Sulfur Feed	1.5 wt. % Sulfur Feed	3.5 wt. % Sulfur Feed
Direct Operating Costs			
Labor	53.7	53.7	53.7
Maintenance	129	129	129
Utilities			
Electricity	71.6	71.6	71.6
Water	30.6	30.6	30.6
Compressed Air	0.4	0.4	0.4
Caustic Soda (Soda Ash)	506 (313)	1,860 (1,150)	3,480 (2,150)
Steam	3.2	3.2	3.2
Polyelectrolyte	14.6	14.6	14.6
Solid Waste Disposal	22.7	22.7	22.7
Liquid Waste Disposal[b]	31.2	31.2	31.2
Indirect Operating Costs			
Tax, Insurance, and Administration	344	344	344
Capital Recovery Cost	1,131	1,131	1,131
TOTAL ANNUAL COST			
Caustic Soda (Soda Ash)	2,340 (2,150)	3,690 (2,980)	5,310 (3,980)
ESP Credit[c]	-429	-429	-429
NET ANNUAL COST			
Caustic Soda (Soda Ash)	1,910 (1,720)	3,260 (2,550)	4,880 (3,550)
EMISSION REDUCTION [Mg SO_x removed/yr]	1,440	5,350	9,990
COST EFFECTIVENESS[d] [$/Mg SO_x removed]	1,330	610	490

[a] Numbers may not add to totals due to rounding. Fourth quarter 1984 dollars.

[b] Assumes liquid waste disposal to sewer, 100 gal/minute.

[c] From Table A-9 in this appendix.

[d] Based on net annual cost with caustic soda.

TABLE A-5. CAPITAL COST FOR SODIUM-BASED JET EJECTOR VENTURI SCRUBBING SYSTEM AND PURGE TREATMENT FOR MODEL UNITS[a]

Capital Costs	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
Direct Costs[b]	4.2	7.2
Indirect Costs	1.6	3.2
Contingency Costs[c]	1.2	2.1
TOTAL CAPITAL COST	7.0	12.5
ESP Capital Cost Credit[d]	-1.0	-1.8

[a] Costs are reported in millions of dollars, adjusted to fourth quarter 1984 dollars, delivered to a Gulf Coast location.

[b] Materials and labor.

[c] Twenty percent of total direct and indirect costs.

[d] From Table A-9 in this appendix; cost provided for comparison purposes.

TABLE A-6. ANNUAL COST OF SODIUM-BASED JET EJECTOR VENTURI SCRUBBING FOR 2,500 m^3/sd MODEL UNITS

Annual Costs	Annual Cost, in Thousands of Dollars[a]	
	1.5 wt. % Sulfur Feed	3.5 wt. % Sulfur Feed
Direct Operating Costs		
Labor	53.7	53.7
Maintenance	105	105
Utilities		
Electricity	304	304
Water	10.2	10.2
Compressed Air	0.3	0.3
Caustic Soda (Soda Ash)	568 (341)	1,083 (650)
Steam	1.1	1.1
Polyelectrolyte	5.2	5.2
Solid Waste Disposal	7.1	7.1
Liquid Waste Disposal[b]	31.1	31.1
Indirect Operating Costs		
Tax, Insurance, and Administration	280	280
Capital Recovery Cost	921	921
TOTAL ANNUAL COST Caustic Soda (Soda Ash)	 2,290 (2,060)	 2,800 (2,370)
ESP Credit	-272	-272
NET ANNUAL COST Caustic Soda (Soda Ash)	 2,020 (1,790)	 2,530 (2,100)
EMISSION REDUCTION [Mg SO_x removed/yr]	1,610	3,070
COST EFFECTIVENESS[c] [$/Mg SO_x removed]	1,250	820

[a] Numbers may not add to totals due to rounding. Fourth quarter 1984 dollars.

[b] Assumes liquid waste disposal to sewer, 50 gal/minute.

[c] Based on net annual cost with caustic soda.

TABLE A-7. ANNUAL COST OF SODIUM-BASED JET EJECTOR VENTURI SCRUBBING FOR 8,000 m^3/sd MODEL UNITS

Annual Costs	Annual Cost, in Thousands of Dollars[a]	
	1.5 wt. % Sulfur Feed	3.5 wt. % Sulfur Feed
Direct Operating Costs		
Labor	53.7	53.7
Maintenance	188	188
Utilities		
Electricity	976	976
Water	30.7	30.7
Compressed Air	0.4	0.4
Caustic Soda	1,818	3,606
(Soda Ash)	(1,101)	(2,183)
Steam	3.4	3.4
Polyelectrolyte	15.6	15.6
Solid Waste Disposal	22.7	22.7
Liquid Waste Disposal[b]	62.3	62.3
Indirect Operating Costs		
Tax, Insurance, and Administration	500	500
Capital Recovery Cost	1,644	1,644
TOTAL ANNUAL COST		
Caustic Soda	5,310	7,100
(Soda Ash)	(4,600)	(5,680)
ESP Credit	-429	-429
NET ANNUAL COST		
Caustic Soda	4,880	6,670
(Soda Ash)	(4,170)	(5,250)
EMISSION REDUCTION [Mg SO_x removed/yr]	5,160	9,840
COST EFFECTIVENESS[c] [$/Mg SO_x removed]	940	680

[a] Numbers may not add to totals due to rounding. Fourth quarter 1984 dollars.

[b] Assumes liquid waste disposal to sewer, 100 gal/minute.

[c] Based on net annual cost with caustic soda.

TABLE A-8. DUAL ALKALI SCRUBBING SYSTEM COSTS BASED ON 1.5 WEIGHT PERCENT SULFUR FEED[a]

Cost	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
CAPITAL COSTS		
Direct Costs	2,500	4,400
Indirect Costs	1,100	2,000
Contingency Costs	700	1,300
TOTAL CAPITAL COST	4,300	7,700
ESP Capital Cost Credit	(1,000)	(1,800)
ANNUAL COSTS		
Direct Operating Costs		
Operating Labor	38	75
Maintenance	65	116
Utilities		
Soda Ash	9	33
Lime	101	316
Electricity	61	191
Water	2	5
Waste Disposal	125	393
Indirect Operating Costs		
Tax, Insurance, and Administration	172	308
Capital Recovery Cost	565	1,013
TOTAL ANNUAL COSTS	1,140	2,450
ESP Credit	(272)	(429)
NET ANNUAL COST	870	2,020
EMISSION REDUCTION [Mg SO_2 removed/yr]	1,670	5,350
COST-EFFECTIVENESS [\$/Mg of SO_2 removed]	520	380

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[a] Costs are reported in thousands of dollars, adjusted to fourth quarter 1984 dollars.

TABLE A-9. ELECTROSTATIC PRECIPITATOR COSTS[a]
(Fourth Quarter 1984 Dollars)

Costs	2,500 m^3/sd Model Unit	8,000 m^3/sd Model Unit
CAPITAL COSTS		
Equipment Costs		
Control Device[b]	324,000	542,000
Auxiliaries[c]	43,400	81,100
Instruments and Controls[d]	36,700	62,300
Taxes and Freight[e]	29,400	49,800
Installation Costs[f]	611,000	1,037,000
TOTAL CAPITAL COSTS	1,045,000	1,772,000
ANNUAL COSTS		
Direct Costs		
Operating Labor[g]	27,000	27,000
General Maintenance[h]	28,100	28,100
Replacement Parts[i]	820	1,380
Utilities[j]	11,000	35,200
Waste Disposal[k]	7,840	25,100
Indirect Costs		
Overhead[l]	32,800	32,800
Property Tax, Insurance, and Administration[m]	41,800	70,900
Capital Recovery Cost[n]	122,800	208,200
TOTAL ANNUAL COSTS	272,000	429,000

TABLE A-9. FOOTNOTES

[a] Fourth quarter 1984 dollars.

[b] Removal efficiency = 95 percent; drift velocity = 0.076 m/sec; plate area for the 2,500 m^3/sd unit = 1,000 m^2, for the 8,000 m^3/sd unit = 3,200 m^2; air flow for the 2,500 m^3/sd unit = 27 m^3/sec, for the 8,000 m^3/sd unit = 87 m^3/sec. Docket A-79-09; item II-I-11.

[c] Auxiliaries include bypass ducting: 19.7 m length, 127 cm diameter, 6.4 mm carbon steel, insulated; 2 elbows 6.4 mm carbon steel, insulated; 2 expansion joints; 2 round dampers with automatic controls; and a 23 cm x 4.5 m screw conveyor. Docket A-79-09, items II-A-5, II-E-5, and II-E-95.

[d] Instrument and controls calculated as 10 percent of control device and auxiliary equipment cost. Docket A-79-09, item II-A-5.

[e] Taxes and freight calculated as 8 percent of control device and auxiliary equipment cost. Docket A-79-09, item II-A-5.

[f] Includes indirect and direct installation costs and 20 percent contingency calculated as 141 percent of purchased equipment cost. Indirect installation costs include costs for foundations and supports, erection and handling, electrical work, piping, insulation, and piping. Docket A-79-09, item II-A-5.

[g] Includes operator and supervisor costs. Operating labor costs are based on 1.25 operator man-hours per shift, 3 shifts per day, 365 days per year and $17.51 per man-hour. Supervisor labor costs are included by adding 15 percent to the operator costs. Docket A-79-09, item II-A-5.

[h] Includes labor and material costs. Maintenance labor costs are based on 0.75 man-hours per shift, 3 shifts per day, 365 days per year, and $17.51 per man-hour. Material costs are equal to 100 percent of maintenance labor costs. Docket A-79-09, item II-A-5.

[i] Based on 0.078 percent of total capital costs. Docket A-79-09, item II-A-24.

[j] Based on 16.15 watts/m_2 plate area, 357 days per year, $0.0795 per kWh, and 1,000 m^2 plate area for the small ESP and 3,200 m^2 plate area for the large ESP. Docket A-79-09, item II-A-5.

[k] Cost to remove waste is based on $16.50/metric ton. Docket A-79-09, items II-I-82, and II-A-5.

[l] Overhead calculated as 80 percent operating labor and maintenance (labor only). Docket A-79-09, item II-A-5.

[m] Calculated as 4 percent of total installed capital cost. Docket A-79-09, item II-A-5.

[n] Capital recovery cost based on 20 years operating life, and 20 percent annual interest rate. Capital recovery factor = 0.1175. Docket A-79-09, item II-A-5.

TABLE A-10. FIFTH YEAR CAPITAL COST IMPACTS[a]

NEW FCCU CONSTRUCTION (1984-1989)

Fresh Feed Capacity (m^3/sd)	Feed Sulfur Content (wt. %)	Number of Units: A	Capital Cost Per Unit: B ($ Millions)	Capital Cost: A x B ($ Millions)
2,500[b,c]	0.3	1	5.0	5.0
8,000[b,c]	0.3	1	8.6	8.6
2,500[b]	1.5	3	5.0	15.0
8,000[b]	1.5	3	8.6	25.8
2,500[b]	3.5	1	5.0	5.0
8,000[b]	3.5	1	8.6	8.6
TOTAL CAPITAL COST IMPACT				68.0

MODIFIED/RECONSTRUCTED FCCU's (1984-1989)

Fresh Feed Capacity (m^3/sd)	Feed Sulfur Content (wt. %)	Number of Units: A	Capital Cost Per Unit: B ($ Millions)	Retrofit Cost Adjustment[e]: C ($ Millions/Unit)	Capital Cost: A x (B + C) ($ Millions)
2,500[d]	1.5	1	7.0	--	7.0
2,500[b]	1.5	1	5.0	0.8	5.8
8,000[b]	1.5	1	8.6	--	8.6
8,000[d]	1.5	1	12.5	--	12.5
8,000[b]	1.5	2	8.6	1.4	20.0
8,000[b]	3.5	1	8.6	--	8.6
TOTAL CAPITAL COST IMPACT					62.5

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[a] 4th quarter 1984 dollars.

[b] High-energy venturi scrubber.

[c] At a feed sulfur content of higher than 0.3 percent, the 90 percent emission reduction standard would need to be met, and this cost would be incurred. At feed sulfur contents of 0.3 percent or less, the regenerator would not be required to meet the standard, and this cost would not be incurred.

[d] Jet-ejector venturi scrubber.

[e] 20 percent of direct and indirect capital cost; excludes ESP credit.

TABLE A-11. FIFTH YEAR ANNUAL COST IMPACTS[a]

Fresh Feed Capacity (m^3/sd)	Feed Sulfur Content (wt. %)	Number of Units: A	Annual Cost Per Unit: B ($ 1,000's)	Annual Cost A x B ($ 1,000's)
2,500[b,c]	0.3	1	930	930
2,500[b]	1.5	3	1,360	4,080
2,500[d]	1.5	1	2,020	2,020
2,500[b,e]	1.5	1	1,780	1,780
2,500[b]	3.5	1	1,870	1,870
8,000[b,c]	0.3	1	1,910	1,910
8,000[b]	1.5	4	3,260	13,040
8,000[d]	1.5	1	4,880	4,880
8,000[b,e]	1.5	2	3,950	7,900
8,000[b]	3.5	2	4,880	9,760
TOTAL ANNUAL COST IMPACT				48,170

[a] 4th quarter 1984 dollars.

[b] High-energy venturi scrubber.

[c] At a feed sulfur content of higher than 0.3 percent, the 90 percent emission reduction standard would need to be met, and this cost would be incurred. At feed sulfur contents of 0.3 percent or less, the regenerator would not be required to meet the standard, and this cost would not be incurred.

[d] Jet-ejector venturi scrubber.

[e] Annualized capital cost includes retrofit cost; excludes ESP credit.